Saskatchewan

Rate Review Panel

Report to the Minister of Crown Investments Corporation on:

The Proposals from SaskEnergy for Changes in Gas Consumption and Delivery Rates

November 23, 2000

Saskatchewan

Rate Review Panel

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November 23, 2000

Honourable John Nilson, Q.C.
Minister of Crown Investments Corporation
Room 361, Legislative Building
Regina, Saskatchewan S4S 0B3

Dear Minister:

As instructed in your Minister's Order dated October 5, 2000, the Saskatchewan Rate Review Panel has completed its review of the proposals by SaskEnergy for changes in rates charged for gas consumption and delivery. Attached for your consideration is the Panel's Report with respect to the proposed rate changes.

In conducting its review, the Panel received advice from a variety of interested parties and the general public through meetings and submissions received through the mail, by facsimile, by telephone and through electronic mail systems. The Panel also engaged the services of a consultant to provide expert advice.

The Panel received excellent co-operation from officials at SaskEnergy and wishes to express its appreciation for their responsiveness in providing clarification, explanation and additional information to meet the Panel's needs.

The Panel is satisfied that its recommendations with respect to the rate proposals are fair and reasonable within the mandate established by the Minister's Order.

The Panel wishes to thank you for this opportunity to provide this advice and to transmit to you the outcome of its deliberations.

Yours truly,

Bob Lacoursiere

Bob Lacoursiere, CA, CMC, RFP., Chair

Attachment (1)

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Introduction

The Saskatchewan Rate Review Panel (the "Panel") has been asked by the Government of Saskatchewan to review Crown corporations' requests for monopoly rate changes.

The Panel consists of Bob Lacoursiere (Chair), Tracey Bakkeli, Jack Boan (Vice Chair), Jo-Ann Carignan-Vallee, Sheldon Craig and Joan Meyer. Each member of the Panel has been appointed until July 25, 2002.

MANDATE

In its general mandate, the Panel is instructed to conduct reviews and provide opinions on the fairness and reasonableness of proposed Crown corporation rate changes referred by the Minister of Crown Investments Corporation, considering the interests of the customer, the corporation and the public.

In conducting its reviews, the Panel is required to:

- receive a rate change submission from a Crown corporation;
- establish procedures for conducting the review and ensure that these procedures are made available to the public;
- engage the services of a consultant(s) to assist the Panel in its review of the fairness and reasonableness of the proposed rate change;
- make available to the public, prior to holding public meetings, the Crown corporation rate change submission, with the exception of commercially sensitive information;
- hold public meetings and provide appropriate notification to the public of the date and location of public meetings, including any rules for public participation and Crown corporation participation;
- provide members of the public with the opportunity to review and comment on the proposed rate changes to the extent reasonably allowed by the mandate of the Panel and by the schedule according to which the Panel is required to complete its work and provide its report to the Minister of Crown Investments Corporation;
- receive presentations of the consultant(s) or the Crown corporation, review any written submissions and receive comments from the public;
- prepare a report on the Crown corporation rate change submission for the Minister of Crown Investments Corporation after considering the material received from the Crown corporation, the consultant(s), the public and its own analysis:
    - where the Panel determines the rate changes as proposed are fair and reasonable, recommend that the changes be implemented; or,
    - where the Panel determines the rate changes are not fair and reasonable as proposed, recommend that the rate changes be adjusted providing reasons for this conclusion;

- provide its report respecting the proposed rate changes to the Minister of Crown Investments Corporation on a date set out in or within any time period after having received the rate change submission that is contained in the specific terms of reference for particular Crown corporation rate reviews; and,
- make its report available to the public.

TERMS OF REFERENCE

On October 5, 2000, the Panel was instructed to conduct a review of the SaskEnergy proposals for changes in the rates charged for gas consumption and delivery.

With respect to the proposal for gas consumption rates, the Panel was instructed to consider the reasonableness of the proposed changes in the context of:

- SaskEnergy's anticipated cost of gas for the effective term;
- the Gas Purchases Contracts entered into by SaskEnergy for the supply of gas;
- the amount SaskEnergy pays for the transportation of gas;
- the natural gas commodity market conditions at the time of SaskEnergy's contractual commitments; and,
- the disposition of the balance of the Gas Cost Variance Account.

With respect to the proposal for delivery rates, the Panel was instructed to consider the reasonableness of the proposed changes in the context of the following components:

1. SaskEnergy's forecasted delivery cost of service, comprised of:

    - the capacity that SaskEnergy has contracted for transportation and storage service;
    - operating and maintenance expenses;
    - depreciation expense; and,
    - Corporate Capital Tax.

2. The revenue requirement resulting from the delivery cost of service.

In reviewing both proposals, the Panel was instructed to take as given:

- the current operating rate structure;
- the approved capital allocation, annual rate of return target, rate base, and corporate policies;
- the existing service level; and
- the cost of service methodology and resulting study, which allocates SaskEnergy costs between the various rate classes.

The Panel was instructed to present its report to the Minister of Crown Investments Corporation by November 23, 2000 (see Appendix A).

Proposals by SaskEnergy - Consumption and Delivery Rates

The SaskEnergy proposals are for a change in the rates charged for two components of the natural gas charges:

- the gas consumption charge, and,
- the delivery charge.

GAS CONSUMPTION CHARGES

SaskEnergy charges customers for the cost of natural gas used. This charge appears separately on a customer's bill and was established for the 1999-2000 heating year, which is from November to October at a rate of 11.10 cents per cubic metre.

The SaskEnergy proposal is to increase this charge to 16.69 cents per cubic metre to reflect the fact that natural gas prices have increased dramatically in the North American market in the past year. According to the SaskEnergy proposal, the new rate would apply to natural gas used between November 1, 2000 and October 31, 2001.

GAS DELIVERY CHARGES

SaskEnergy has also proposed an increase in the charges for gas delivery averaging 2.4 per cent.

The gas delivery charge to a customer has two components:

- a basic charge, and
- a variable charge based on usage.

Residential gas customers currently pay a basic gas delivery charge of $10.50 per month and an additional charge of 7.1 cents per cubic metre on the natural gas they consume.

SaskEnergy has proposed that the residential basic delivery charges be increased by $0.75 per month to $11.25 per month, with no change in the variable portion of the delivery charges.

SaskEnergy has proposed to increase the basic monthly rate for farm customers from the current rate of $11.55 per month to $12.30 per month, an increase of $0.75 per month.

Small commercial customers pay a basic service rate of $17.00 per month and a variable service rate of 6.31 cents per cubic. Large commercial customers pay a basic service rate of $37.25 per month and a variable service rate of 5.51 cents per cubic metre.

The SaskEnergy proposal would increase variable rates from 6.31 cents to 6.5 cents per cubic metre for small commercial customers and from 5.51 cents to 5.65 cents per cubic metre for large commercial customers. The SaskEnergy proposal would not increase the basic service rates charged for commercial customers.

Comparison of Natural Gas Consumption and Service Charges

	Current (1999-2000) Rate	SaskEnergy Proposed 2000-01 Rate
Residential Customer:		
- Gas Consumption Charge	$0.1110 per cubic metre	$0.1669 per cubic metre
- Delivery - Basic	$10.50 per month	$11.25 per month
- Delivery - Volume Charge	$0.071 per cubic metre	$0.071 per cubic metre
Farm Customer:		
- Gas Consumption Charge	$0.1110 per cubic metre	$0.1669 per cubic metre
- Delivery - Basic	$11.55 per month	$12.30 per month
- Delivery - Volume Charge	$0.071 per cubic metre	$0.071 per cubic metre
General Service II Customer:		
- Gas Consumption Charge	$0.1110 per cubic metre	$0.1669 per cubic metre
- Delivery - Basic	$17.00 per month	$17.00 per month
- Delivery - Volume Charge	$0.0631 per cubic metre	$0.0650 per cubic metre
General Service III Customer:		
- Gas Consumption Charge	$0.1110 per cubic metre	$0.1669 per cubic metre
- Delivery - Basic	$37.25 per month	$37.25 per month
- Delivery - Volume Charge	$0.0551 per cubic metre	$0.0565 per cubic metre

Note: Farm and Agricultural rates apply from 0 to 10,000 cubic metres of annual consumption.
General Service II rates cover commercial users with 0 to 100,000 cubic metres of annual consumption.
General Service III rates cover commercial or industrial users with 100,001 to 660,000 cubic metres of annual consumption.

The Review Process

PUBLIC CONSULTATIONS

In reviewing the SaskEnergy proposals, the Panel received comments and suggestions from individuals and groups throughout Saskatchewan through a public consultation process that included:

- four public meetings;
- establishment of a toll-free telephone message line;
- receipt of submissions by mail;
- receipt of messages by facsimile; and,
- receipt of electronic message correspondence.

These methods of public discussion were advertised in daily newspapers and in weekly newspapers. In addition, radio clips were played on local radio stations.

Panel members were also involved in numerous media interviews and public appearances.

Copies of the SaskEnergy rate proposals were available to the public at SaskEnergy offices, at the public meetings and on the Internet.

The four public meetings were held on:

- October 23 at the West Harvest Inn in Regina;
- October 24 at the Prince Albert Inn in Prince Albert;
- October 30 at the Sandman Inn in Saskatoon; and,
- November 7 at the Best Western Westridge Motor Inn in Kindersley.

Meetings were also scheduled for November 1 at the Lucky Goose Lodge in Weyburn and November 2 at the Travelodge Hotel in Yorkton but were canceled due to adverse weather.

The meetings included:

- an introduction by the Chair with an explanation of the proceedings and the Panel's mandate for the review;
- an overview by SaskEnergy of its request;
- an opportunity for submissions by individuals or organizations that had indicated an interest in addressing the Panel; and,
- an opportunity for questions or comments from the floor.

CONSULTANT

In conducting its review, the Panel engaged the services of a consultant to examine and advise on the reasonableness and fairness of the SaskEnergy proposals.

The British Columbia Utilities Commission was contracted to provide consulting services to the Panel. Staff assigned to the review by the Commission have over 40 years experience in utilities regulation and served as consultants to the Saskatchewan Interim Rate Review Panel in the examination of the SaskEnergy rate request in 1999.

PRESENTATIONS

As required in its mandate, the Panel received presentations from officials of SaskEnergy and from its consultant at several points throughout the review process to:

- develop an understanding of the proposed rate changes;
- understand the analyses prepared for the Panel; and,
- develop its recommendations.

PANEL'S REPORT

The Panel has prepared a report highlighting the results of its consultation process, its own analysis and its recommendations to the Minister of Crown Investments Corporation.

Summary of Consultant's Report

The Panel met with the consultant and subsequently sought additional information from SaskEnergy officials on the rate proposals.

The consultant also provided briefings to the Panel on specific issues and prepared a final report and assessment of the SaskEnergy submissions (attached as Appendix B).

DELIVERY RATES

The consultant recommended that there be no change in delivery rates at this time, noting that, increases in productivity which might be realistically expected based on past performance and additional volumes in line with past growth should allow SaskEnergy to absorb expected cost increases in other areas and remove the need for a rate increase for delivery services.

GAS CONSUMPTION CHARGES

The consultant advised the Panel that "the forecast set out in SaskEnergy's Commodity Rate Application and the rate derived from it are generally fair and reasonable", noting that market prices for natural gas have been much higher than levels experienced in the past. The consultant also noted that SaskEnergy "is doing an efficient job of mitigating costs during this period of high North American demand and constrained production capability" through the use of gas held in storage and in the use of gas supply contracts.

Gas Cost Variance Account

As a change in policy in 1999-2000, SaskEnergy introduced the use of a **Gas Cost Variance Account** which will allow the corporation to account more transparently for any deficiency or surplus in the revenue from charges levied on customers.

Thus, if the rates established for natural gas consumption ultimately prove to be higher than the cost to SaskEnergy to purchase gas in the course of a year, the "surplus" would accrue in the Gas Cost Variance Account and could be applied to reduce gas consumption rates from the level they would otherwise be in subsequent periods.

Conversely, if it proves to be the case that the gas consumption charges in any gas year are inadequate to cover the actual cost of gas purchased in that year, the "deficit" in the Gas Cost Variance Account would be added into the calculation of gas consumption charges in subsequent periods.

According to the consultant's report to the Panel, this Variance Account is beginning the 2000-01 gas year with a small surplus and this surplus can be applied to mitigate to some degree the increase in gas commodity rates for 2000-01. It should be noted that the consultant's report includes a higher estimate of the November 1, 2000 surplus balance in the Variance Account ($1.7 million) than that included in the SaskEnergy proposal ($0.2 million).

On the other hand, the consultant notes that the gas year began on November 1, 2000 and there is no capacity to increase gas consumption rates prior to December 1, 2000. With the loss of the increased revenue from gas consumption charges for the month of November, it is the consultant's view that there would be a significant shortfall in revenue against actual natural gas costs even if the Panel were to recommend an increase in gas consumption charges to $0.1669 per cubic metre as originally requested by SaskEnergy.

The consultant advised the Panel the net effect of these considerations could leave the Variance Account with a shortfall of $12.7 million by the end of October 2001, unless rates are adjusted to prevent this shortfall.

Accordingly, the consultant advised the Panel to allow SaskEnergy to increase the consumption rates beyond the requested level of $0.1669 per cubic metre to $0.1741 per cubic metre effective December 1, 2000 to be able to recover the anticipated costs on gas supply (for the whole year) over the 11 months remaining in the gas year.

In effect, the consultant agreed with the SaskEnergy proposal for an increase in gas consumption charges to an average of $0.1669 over the gas year (November to October) and suggested that average could be achieved by raising gas consumption rates to $0.1741 for the eleven-month period from December to October.

The consultant further recommended SaskEnergy formally advise the Panel of the Variance Account balance at March 31 and any actions it proposes to take as a result.

The consultant also recommended that SaskEnergy record its budgeted amount of non-storage interest Other Operating Expense (that is, $997,000) in the Variance Account for 2000-2001, regardless of the actual costs incurred in these areas.

In addition, the consultant suggested that a shared services study should be undertaken by SaskEnergy to ensure that costs are properly allocated among functions when shared services are involved.

Panel Conclusions and Recommendations

DELIVERY RATES

The SaskEnergy proposal was for an increase in delivery rates of 2.4 per cent to be effective November 1, 2000.

The Panel notes that there has not been an increase in gas delivery charges since 1997 and there has been only that one increase in the past seven years. The Panel makes specific note of the commendable efforts on the part of SaskEnergy to constrain delivery costs and, in the process, avoid delivery charge increases in recent years.

The Panel considered carefully the advice of the consultant and the comments received from the public and is of the opinion that, while there are reasons to expect that the costs of delivery of gas will increase, there may be offsetting compensations to be expected.

For example, wages may be expected to increase over the next year. But, on the other hand, it is also reasonable to expect that productivity will increase over time. These two contrary pressures will tend to offset one another.

In addition, some of the pressure on delivery costs is relieved by the decision to charge some of SaskEnergy's interest costs against the cost of the commodity as being a cost of maintaining the commodity as inventory in storage. This is a legitimate treatment of interest charges and it will allow the corporation some latitude in containing its delivery costs, especially when combined with the productivity considerations noted above.

Accordingly, the Panel recommends that an increase in the delivery rates as proposed by SaskEnergy not be allowed at this time.

GAS CONSUMPTION CHARGES

SaskEnergy's request was for an increase in gas consumption rates from the 1999-2000 rate of 11.1 cents per cubic metre to 16.69 cents per cubic metre, effective November 1, 2000.

In the course of its review, the Panel noted that market prices for natural gas have increased dramatically in North America with prices recently exceeding twice the level they were a year ago.

These market conditions were also noted by the consultant as undeniably important in the consideration of SaskEnergy's proposed rate changes.

The Panel was also advised by the consultant that SaskEnergy's efforts to secure long-term supply contracts under favourable market conditions and the corporation's effective use of storage capacity and access to markets to meet peak load requirements have provided great benefits to Saskatchewan customers.

While these efforts have been effective in providing an advantage to Saskatchewan customers, they cannot completely insulate customers from conditions in the international natural gas market.

Careful scrutiny by the consultant led to its recommendation to the Panel that the rates be approved as requested, noting that SaskEnergy's forecasts of the cost of gas over the gas year were reasonable in light of current market conditions.

Accordingly, the Panel recommends that SaskEnergy be allowed to increase charges for the cost of gas from 11.10 cents per cubic metre to 16.69 cents per cubic metre as requested by the SaskEnergy submission.

EFFECTIVE DATE

The initial request from SaskEnergy was for the new rates for both delivery and consumption charges to take effect on November 1, 2000, to coincide with the start of the natural gas year which runs from November 1 to October 31.

Considering that the Panel's recommendations will not be made to the Minister of Crown Investments Corporation until November 23, 2000, in accordance with the Ministerial Order of October 5 mandating the review, and allowing time for any new rates to be implemented, a November 1 implementation date is not attainable.

Since the Panel is recommending an increase in consumption rates, the effective date of those higher consumption charges will affect the revenue to SaskEnergy and the ultimate cost to gas customers over the gas year.

In light of this, the Panel considered three options for recognition of the delay in implementation of any new rates, specifically:

- retroactive implementation to November 1;
- implementation on December 1 at a higher rate to capture 12 months revenue over the remaining 11 months of the gas year; and,
- implementation on December 1 at the recommended annual rate.

Retroactive Implementation

It has not been the practice to implement higher gas rates retroactively in recognition that the customer base does change over time. The Panel decided to avoid retroactivity to avoid the confusion that could be caused by issuing amended bills for a past period when customers are unable to engage in strategies such as conservation measures to avoid higher charges.

Recovery Over Eleven Months

Given that a December 1 implementation appears to be practical, it would be possible to implement a

higher rate on December 1 such that, on average over the full gas year, the rate of 16.69 cents per cubic metre recommended by the Panel is achieved.

This calculation would be as follows:

Period	Estimated Consumption (millions of cubic metres)	Rate (cents/cubic metre)	Total Revenue ($ millions)
November	199.9	11.10	$22.2
December-October	1,549.0	17.41*	$269.7
Gas Year Total	**1,748.9**	**16.69**	**$291.9**

* Derived

Thus, to average an annual rate of 16.69 cents per cubic metre, a rate of 17.41 cents per cubic metre could be implemented on December 1 such that, when averaged with the rate of 11.10 cents per cubic metre in place for the month of November, customers would have paid and effective rate of 16.69 cents per cubic metre for the gas year. This approach was recommended to the Panel by the consultant.

No Recovery of November Shortfall

Alternatively, the Panel considered establishing a rate of 16.69 cents per cubic metre as requested by SaskEnergy but to have that rate apply only on consumption after December 1, 2000. The effect of this approach would be as follows:

Period	Estimated Consumption (millions of cubic metres)	Rate (cents/cubic metre)	Total Revenue ($ millions)
November	199.9	11.10	$22.2
December-October	1,549.0	16.69	$258.5
Gas Year Total	**1,748.9**	**16.05***	**$280.7**

* Derived

In this case, the customer would pay the Panel's recommended higher rate beginning December 1 but, with November already past at the lower rate of 11.10 cents per cubic metre, would only face an average rate of 16.05 cents per cubic metre over the gas year.

It is significant as well that, under this third approach to implementation, SaskEnergy would receive less revenue ($11.2 million) over the course of the gas year than would be the case under the earlier approach and less than recommended to the Panel by the consultant.

The Panel notes that SaskEnergy has established a Gas Cost Variance Account in its operations. The purpose of this account is to track any discrepancy between the price of gas sold by SaskEnergy under the regulated price and the actual cost of the gas purchased by SaskEnergy over the period.

While it is expected that SaskEnergy will need a total of $292 million between November, 2000 and October, 2001 to cover the cost of gas purchased, the actual costs will depend on the market prices for gas over that period. This will not be known until the close of the gas year October 31, 2001. It is anticipated that any shortfall or excess collected by SaskEnergy would be applied in the calculation of gas consumption charges for the 2001-2002 gas year.

SaskEnergy and the consultant both advised the Panel that applying a rate of 16.69 cents per cubic metre effective December 1 can be expected to lead to a shortfall in the Gas Cost Variance Account which would have to be considered in the establishment of any rates to be applied in the 2001-2002 gas year.

Nevertheless, the Panel notes this expectation can only be tested against actual results for the year and feels that to the extent there is uncertainty in natural gas prices, this uncertainty should not fall unduly on either the customers nor SaskEnergy.

Accordingly, the Panel recommends the gas consumption rate of 16.69 cents per cubic metre recommended above come into effect on December 1, 2000 and not be applied retroactively to the month of November, 2000.

But, to ensure that a shortfall does not develop to the point of jeopardizing the stability of SaskEnergy, the Panel recommends that the Minister instruct SaskEnergy to review the Gas Cost Variance Account after March 31, 2001 and consider allowing SaskEnergy to return with a rate change if the balance in the Variance Account exceeds $20 million (surplus or deficit).

The Panel also recommends that the balance calculated for the Gas Cost Variance Account at November 1, 2000 be considered to be $1.8 million as recommended by the Panel's consultant.

Summary of Recommendations

DELIVERY CHARGES

The Panel recommends that there be no increase in delivery charges in for the 2000-01 gas year.

CONSUMPTION CHARGES

The Panel recommends that gas consumption charges be increased from the current rate of 11.10 cents per cubic metre to a rate of 16.69 cents per cubic metre.

EFFECTIVE DATE

The Panel recommends that the new rate come into effect on December 1, 2000.

GAS COST VARIANCE ACCOUNT

The Panel recommends that the surplus value of the Variance Account be established at $1.8 million as at November 1, 2000 and that, if the balance exceeds $20 million (deficit or surplus) on March 31, 2001, the Minister should consider allowing SaskEnergy to return with a rate change proposal.

IMPACT ON CUSTOMERS

The Panel's recommendation that there be no increase in delivery rates this year will save customers of gas a total of $3.6 million relative to the SaskEnergy request. This amount represents approximately 2.4 per cent of the average gas bill.

For residential and farm customers, this will translate into savings of approximately $9.00 over the period of November, 2000 to October 2001.

The recommendation to allow the increase in gas consumption rates only on December 1, 2000 will defer gas costs to customers (for the month of November) of approximately $11.2 million to the 2001-2002 gas year.

Comparison of Natural Gas Consumption and Service Charges

	SaskEnergy Proposed 2000-01 Rate	Saskatchewan Rate Review Panel Recommended Rate
Residential Customer:		
- Gas Consumption Charge	$0.1669 per cubic metre	$0.1669 per cubic metre*
- Deliver - Basic	$11.25 per month	***$10.50 per month***
- Delivery - Volume Charge	$0.071 per cubic metre	$0.071 per cubic metre
Farm Customer:		
- Gas Consumption Charge	$0.1669 per cubic metre	$0.1669 per cubic metre*
- Delivery - Basic	$12.30 per month	***$11.55 per month***
- Delivery - Volume Charge	$0.071 per cubic metre	$0.071 per cubic metre
General Service II Customer:		
- Gas Consumption Charge	$0.1669 per cubic metre	$0.1669 per cubic metre*
- Delivery - Basic	$17.00 per month	$17.00 per month
- Delivery - Volume Charge	$0.0650 per cubic metre	**$0.0631 per cubic metre**
General Service III Customer:		
- Gas Consumption Charge	$0.1669 per cubic metre	$0.1669 per cubic metre*
- Delivery - Basic	$37.25 per month	$37.25 per month
- Delivery - Volume Charge	$0.0565 per cubic metre	***$0.0551 per cubic metre***

*** *Effective December 1, 2000 to October 31, 2001***

Note: Farm and Agricultural rates apply from 0 to 10,000 cubic metres of annual consumption.
General Service II rates cover commercial users with 0 to 100,000 cubic metres of annual consumption.
General Service III rates cover commercial or industrial users with 100,001 to 660,000 cubic metres of annual consumption.

IMPACT ON SASKENERGY

The Panel's recommendation for ***no increase in the delivery charge*** for the 2000-01 gas year will reduce the revenue to SaskEnergy by approximately $3.6 million relative to the proposal from SaskEnergy.

The Panel notes that SaskEnergy has been able to find efficiencies in its operations in the past which have been sufficient to avoid increases in the charges for delivery without increases in revenue.

With the establishment of a Gas Cost Variance Account, there is no long-term cost to SaskEnergy of any divergence of actual gas costs from those forecasted for rate setting purposes. If gas costs are higher than anticipated, the shortfall will accumulate in the Gas Cost Variance Account and be recouped in the calculation of rates in subsequent periods.

IMPACT ON THE PUBLIC

The rate changes recommended by the Panel:

- recognize the rapidly rising cost of natural gas in North American markets;
- provide incentives for continued efficiency in operation at SaskEnergy; and,
- minimizes the impact of rising gas costs in 2000-2001 on Saskatchewan customers.

It is the Panel's view, therefore, that the rate changes recommended by the Panel are fair and reasonable, considering the interests of the customer, the Crown corporation and the public.

Appendix A: Minister's Orders
SaskEnergy Delivery Rate Change
SaskEnergy Gas Consumption Rate Change

MINISTER'S ORDER

Saskatchewan Rate Review Panel
SaskEnergy Delivery Rate Change

WHEREAS by a Minister's Order dated July 27, 2000, issued pursuant to section 16 of *The Government Organization Act*, the Minister of Crown Investments Corporation appointed a ministerial advisory committee known as the Saskatchewan Rate Review Panel.

WHEREAS that Minister's Order provides for specific terms of reference for particular Crown corporation rate change reviews to be attached by further minister's order.

WHEREAS it is desirable to establish terms of reference for a SaskEnergy delivery rate change review and to attach the terms of reference to the previously mentioned Minister's Order.

NOW THEREFORE I hereby amend the said Minister's Order by attaching Appendix A affixed hereto as **"Schedule B: SaskEnergy Delivery Rate Change Terms of Reference"** to the said Minister's Order.

Dated at the City of Regina, Saskatchewan, this 5th day of October, 2000.

Minister of Crown Investments Corporation

APPENDIX A

Schedule B:
SaskEnergy Delivery Rate Change Terms of Reference

Terms of Reference

The Saskatchewan Rate Review Panel is requested to conduct a review of SaskEnergy's request for an increase in its delivery rates for the term November 1, 2000 to October 31, 2001.

The Panel shall provide an opinion of the fairness and reasonableness of SaskEnergy's proposed rate changes, considering the interests of the customer, the Crown corporation and the public.

In conducting its review, the Panel will consider the following factors:

The reasonableness of the proposed changes to the delivery rates, in the context of the following components:

1. SaskEnergy's forecasted delivery cost of service, comprised of:

I. the capacity that SaskEnergy has contracted for transportation and storage service;
II. operating and maintenance expenses;
III. depreciation expense; and
IV. Corporate Capital Tax.

2. The revenue requirement resulting from the delivery cost of service.

In conducting its review, the Panel shall consider the following as given:

I. the current operating rate structure;
II. the approved capital allocation, annual rate of return target, rate base, and corporate policies;
III. the existing service level; and
IV. the cost of service methodology and resulting study, which allocates SaskEnergy costs between the various rate classes.

The Panel will not publicly release or require SaskEnergy to publicly release commercially sensitive material.

Conduct of Review

The Panel will present its report to the Minister of Crown Investments Corporation no later than November 23, 2000.

MINISTER'S ORDER

Saskatchewan Rate Review Panel
SaskEnergy Gas Consumption Rate Change

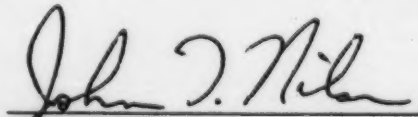
WHEREAS by a Minister's Order dated July 27, 2000, issued pursuant to section 16 of *The Government Organization Act*, the Minister of Crown Investments Corporation appointed a ministerial advisory committee known as the Saskatchewan Rate Review Panel.

WHEREAS that Minister's Order provides for specific terms of reference for particular Crown corporation rate change reviews to be attached by further minister's order.

WHEREAS it is desirable to establish terms of reference for a SaskEnergy gas consumption rate change review and to attach the terms of reference to the previously mentioned Minister's Order.

NOW THEREFORE I hereby amend the said Minister's Order by attaching Appendix A affixed hereto as **"Schedule C: SaskEnergy Gas Consumption Rate Change Terms of Reference"** to the said Minister's Order.

Dated at the City of Regina, Saskatchewan, this 5th day of October, 2000.



Minister of Crown Investments Corporation

APPENDIX A

Schedule C:
SaskEnergy Gas Consumption Rate Change Terms of Reference

Terms of Reference

The Saskatchewan Rate Review Panel is requested to conduct a review of SaskEnergy's request for an increase in its gas consumption rates for the term November 1, 2000 to October 31, 2001.

The Panel shall provide an opinion of the fairness and reasonableness of SaskEnergy's proposed rate changes, considering the interests of the customer, the Crown corporation and the public.

In conducting its review, the Panel will consider the following factors:

The reasonableness of the proposed changes to the gas consumption rates in the context of:

I. SaskEnergy's anticipated cost of gas for the effective term;
II. the Gas Purchase Contracts entered into by SaskEnergy for the supply of gas;
III. the amounts SaskEnergy pays for the transportation of gas;
IV. the natural gas commodity market conditions at the time of SaskEnergy's contractual commitments; and
V. the disposition of the balance of the Gas Cost Variance Account.

In conducting its review, the Panel shall consider the following as given:

I. the current operating rate structure;
II. the approved capital allocation, annual rate of return target, rate base, and corporate policies;
III. the existing service level; and
IV. the cost of service methodology and resulting study, which allocates SaskEnergy costs between the various rate classes.

The Panel will not publicly release or require SaskEnergy to publicly release commercially sensitive material including, but not limited to, its gas price hedging strategy and any details of its hedging or the gas purchase contracts.

However, the Panel may release the net effect of SaskEnergy's gas price hedging and gas purchase contracts.

Conduct of Review

The Panel will present its report to the Minister of Crown Investments Corporation no later than November 23, 2000.

Appendix B:
British Columbia Utilities Commission Staff Review Report to the Saskatchewan Rate Review Panel

SASKENERGY INCORPORATED

NATURAL GAS DISTRIBUTION UTILITY

DELIVERY RATE APPLICATION
COMMODITY RATE APPLICATION

for

November 1, 2000 – October 31, 2001

STAFF REVIEW REPORT

November 20, 2000

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SASKENERGY INCORPORATED

DELIVERY RATE APPLICATION
COMMODITY RATE APPLICATION

NOVEMBER 1, 2000 – OCTOBER 31, 2001

BCUC STAFF REVIEW REPORT

1.0 INTRODUCTION

1.1 SaskEnergy Applications

SaskEnergy Incorporated ("SaskEnergy", the "Utility") filed Applications requesting increases in its Delivery Rates and Gas Consumption Charge for the natural gas contract year November 1, 2000 through October 31, 2001. On October 17, 2000, the Utility filed "reworked" versions of the Applications but did not modify the rate increases that it requested.

In the Delivery Rate Application, SaskEnergy requested an average delivery rate increase of 2.4 percent effective November 1, 2000 to recover the increased cost of providing delivery service. The corresponding increase in the annual bill of a typical residential customer would be $9.00 or 1.2 percent. SaskEnergy proposed increases to the Basic Monthly Charge for residential and farm customers of $0.75 per month, and increases in the Delivery Charges for commercial customers of $0.0014 to $0.0019 per cubic metre. Delivery Rates last increased by 2.3 percent in July 1997.

In the Commodity Rate Application, SaskEnergy requested a 50 percent increase in its Gas Consumption Charge from $0.1110 per cubic metre to $0.1669 per cubic metre effective November 1, 2000. The new rate is the forecast cost to SaskEnergy of the natural gas that it will resell to customers. The corresponding increase in the annual bill of a typical residential customer would be $197 or 25.6 percent. The current Gas Consumption Charge went into effect December 15, 1999, and increased a typical residential annual bill by 9.1 percent.

The combined effect of the two rate changes would increase the annual bill of a typical residential customer by $206 or 26.8 percent.

1.2 SaskEnergy and Its Gas Distribution Activities

SaskEnergy is a provincial Crown Corporation operating under The SaskEnergy Act. SaskEnergy has a number of wholly-owned subsidiaries, each operating on a stand-alone basis. One subsidiary is TransGas Limited ("TransGas") which owns and operates natural gas transmission, gathering, compression, treatment and storage facilities in Saskatchewan. TransGas has an exclusive right to transport gas within the province, up to the town border stations where pressure reduction first occurs.

SaskEnergy, as the Distribution Utility, has the exclusive right to distribute gas within Saskatchewan. It delivers gas to approximately 317,000 residential, farm, commercial and industrial customers. Although the facilities of SaskEnergy start at the town border stations, its rates start with gas at the TransGas Energy Pool ("TEP"). TEP is a notional location part way through the TransGas transmission system, which acts as a market hub or interchange point. SaskEnergy contracts with TransGas for gas storage and for transportation capacity from TEP to the SaskEnergy system for its utility sales customers, and also for about 1,000 customers who buy gas directly from other suppliers but use load-shaped and balanced SaskEnergy delivery service. The TransGas transportation and storage costs are recovered from customers in SaskEnergy's Delivery Rates, along with SaskEnergy's costs of providing distribution delivery service.

With the development of competitive gas commodity markets since 1985, most industrial and some larger commercial customers now buy the natural gas commodity directly from a producer or other supplier and use only distribution services from SaskEnergy. Utility sales, where SaskEnergy sells the gas commodity, now represent only about one-half of total SaskEnergy deliveries. SaskEnergy purchases natural gas for its sales customers, and contracts for the transport of the gas to TEP, the notional receipt point for its Delivery Rates. The cost of buying the gas commodity and transporting it to TEP is recovered in the Gas Consumption Charge. In 1998, SaskEnergy redesigned its rates and bills to show the Delivery Rates and the Gas Consumption Charge separately.

Most customers who purchase gas directly from suppliers provide their own storage, load-shaping, and balancing. These customers pay a rate to TransGas that includes distribution on the SaskEnergy system, and SaskEnergy recovers a corresponding payment from TransGas in the form of a Distribution Toll. In a similar arrangement, a larger customer can contract with SaskEnergy for TransGas transportation service and SaskEnergy distribution service. The same rates apply, and SaskEnergy remits payment for the transportation service to TransGas.

Forecast SaskEnergy deliveries for 2000/01 are:

SaskEnergy Delivery Service	Utility sales	64.6 PJ[1]
	Directly purchased	1.9 PJ
		66.5 PJ
SaskEnergy Distribution Service	TransGas customers	68.2 PJ
	SaskEnergy contracts	4.5 PJ
		72.7 PJ
Total Forecast 2000/01 Deliveries		139.2 PJ

[1] A petajoule ("PJ") is one million gigajoules. A terajoule ("TJ") is one thousand gigajoules. A gigajoule ("GJ") is a unit of energy. One GJ is about the amount of energy contained in 27.3 cubic metres or 960 cubic feet of natural gas, or 29 litres of gasoline, or 278 kilowatt hours of electricity, or 0.16 barrels of oil. The amount of natural gas used by individual residential customers varies widely; a typical residential customer consumes about 130 GJ annually for heating and hot water.

1.3 Approval of Rates

SaskEnergy and TransGas establish rates, charges, and terms and conditions of service for the services that each company provides to its customers. Each company must describe all rates and conditions of service in a schedule that is available to the public. The rates are subject to approval by the Saskatchewan Cabinet.

A Minister's Order dated July 27, 2000, pursuant to The Government Organization Act, established the Saskatchewan Rate Review Panel (the "Panel") as a Ministerial Advisory Committee to review and provide an opinion on the fairness and reasonableness of proposed Crown Corporation rate changes, and to consider the interests of the customer, the Crown Corporation and the public in its opinions. Two subsequent Minister's Orders, both dated October 5, 2000, requested that the Panel review SaskEnergy's request for changes to its Delivery Rates and Gas Consumption Charge for the period November 1, 2000 to October 31, 2001, and set out Terms of Reference for the review. The Terms of Reference stated that several matters, including the current operating rate structure, approved capital allocation, annual rate of return target, rate base, and the methodology to allocate cost of service among rate classes, are to be considered as given. The Panel is to present its report to the Minister of Crown Investments Corporation of Saskatchewan by November 23, 2000. The three Minister's Orders are Attachment 1 to this Report.

1.4 Purpose of BCUC Staff Review Report

The staff of the British Columbia Utilities Commission ("BCUC") were engaged by the Panel to undertake a review of the increases in Delivery Rates and the Gas Consumption Charge that SaskEnergy requested. BCUC staff are to provide a recommendation to the Panel as to the fairness and reasonableness of the proposed rate increases, consistent with the Terms of Reference for the Panel's review of SaskEnergy's Applications. BCUC staff will act as independent advisors to the Panel to assist it in providing its recommendations to government with respect to the rate increases. The results of the BCUC staff review are set out in this Report. Attachment 2 of the Report outlines the services to be provided by BCUC staff. Attachment 3 describes the normal role of BCUC staff, outlines the delivery charge and gas cost approval process in British Columbia and provides biographies for staff members Bill Grant, Brian Williston, James Fraser, and Philip Nakoneshny who have prepared the Report.

2.0 LOAD FORECAST

2.1 Annual Load Forecast

SaskEnergy is forecasting annual delivery volumes of 66,984 TJ for the 2000/01 gas contract year, including unmetered consumption and SaskEnergy usage.

To derive its annual load forecast, SaskEnergy multiplies the expected annual use per customer for each customer class under normal weather conditions times the expected average number of customers in each rate class. The assumed use per customer is based generally on weather adjusted data for the past three to five years with some consideration being given to longer term trends. SaskEnergy notes that a trend of declining use per residential customer has been evident in Saskatchewan since 1982 and that this trend is reflected in an assumption of a further 1.3 percent decline for the test year. Moreover, SaskEnergy has reduced its 2000/01 annual forecast load by 37,629 GJ to reflect customer additions anticipated to have lower than class average consumption.

Based on the above methodology, SaskEnergy has forecast the annual load, by class, as follows for the test year period of November 1, 2000 to October 31, 2001:

Customer Class	Average Number of Customers	Forecast Delivery Volumes (TJ/yr)
Residential	259,133	33,717
Farms	22,789	3,162
General Service II	35,153	18,807
General Service III	1,361	10,225
Small Industrial	19	579
Customer Deliveries Total	318,456	66,490
Unaccounted for	–	494
Total		**66,984**

Source: Delivery Rate Application, Schedule 5.1

The average number of customers for each class of customers except the small industrial class has shown moderate growth over the past ten years. The forecast of the average number of customers for each customer class, with the exception of the small industrial classes, shows further expected moderate growth and should be accepted as reasonable.

The forecast number of small industrial customers for 2000/01 (19) has decreased, but appears to be within the range of annual volatility shown in recent past years. The forecast number of small industrial customers is based on the actual number of customers in August 2000 adjusted for anticipated changes prior to November 1, 2000. Given the high degree of past volatility and the small proportion of the total gas load forecast attributed to this customer class (less than 1 percent of the total) this aspect of the forecast should also be accepted as reasonable.

Based on the average annual customer forecast and the total annual forecast delivery volumes, BCUC staff have calculated the assumed annual use per account by customer class (based on Schedule 5.1 in the

Delivery Rate Application), and compared it to the historical 10-year average normalized use per account (derived from SaskEnergy's October 26, 2000 Information Response 10.1).

	SaskEnergy Application Assumed GJ/yr	Historical Average Normalized GJ/yr
Residential	130.3	135
Farm	138.8	182
General Service II	535.0	548
General Service III	7512.9	5889
Small Industrial	30473.7	31425

The general decline in the use per account for the residential customer class has been explained by SaskEnergy in Section 5.1.2 and is consistent with the historical trend shown by the data in SaskEnergy's October 26, 2000 Information Response 10.1.

The farm use per account is 24 percent lower than the historical average and a general trend is not evident from the historical data. No year in the past ten years has a normalized annual use per customer as low as that assumed for 2000/01, and the closest year's consumption of 141 GJ in 1998 appears to have been somewhat of an anomaly. However, SaskEnergy reclassified its farm rate class in late 1996 to exclude customers using more than 10,000 m^3/yr (approximately 370 GJ/yr assuming 0.03694 GJ per cubic metre). As the reclassification was not completed until 1998 and farm meters are read only once per year, the first full year of consumption data for the revised farm class was the September 1998 to August 1999 period. SaskEnergy states that the weather normalized average farm consumption for that period was 139 GJ/account.

However, the farm use per account for the periods November 1998 to October 1999 and November 1999 to October 2000 is 152.2 GJ/yr and 163.9 year respectively (SaskEnergy's October 26, 2000 Information Response 9.1). The average farm use per account for these two years is approximately 158 GJ/yr. Changing the period of analysis slightly can change the average use per account. The weather normalized use per farm customer for the year ending August 2000 was 171 GJ per customer and, for the two-year period ending August 2000, the average use per farm account was 155 GJ. In the view of BCUC staff, using the consumption data for the most recent two gas years (November 1998 to October 2000) is an appropriate period.

Consequently, the assumption of 139 GJ/yr per farm account should be adjusted upwards to be 158 GJ/yr. Using 158 GJ/yr per farm account as the forecast assumption, and the forecast number of accounts of 22,789, provides a forecast sales volume of 3,601 TJ/yr for farm use.

The forecast for the General Service II customer category appears to be close to the historical average and is the same as the actual normalized use per account for 1999. Moreover, the assumed value is well with the range of general volatility for this customer class. The assumption for this customer class appears reasonable.

The assumed use per account for the General Service III category, while significantly higher (26 percent) than the historical average normalized use per account, appears reasonable when viewed in the context of the last three years of data. The average normalized use per account for the past three years (1997-1999) was 7198 GJ, and the normalized use per account for 1999 was 7,346 GJ. Consequently, the assumed use per account for this class appears to reflect recent trends in this customer category.

Finally, the small industrial class category is assumed to consume 30,474 GJ per customer which, while slightly lower than the 10-year average, appears well within the range of volatility of the consumption for this customer class. The assumed value is higher than the consumption range of approximately 20,000 GJ to 22,000 GJ per customer from 1997 to 1999, and lower than the range of approximately 33,000 GJ to 39,000 GJ in the three years previous to that. Therefore, when viewed against the annual normalized consumption of the most recent six years, the assumption appears reasonable.

2.2 Design Peak Day Forecast

SaskEnergy is forecasting a design peak day load of 602,929 GJ for the test year. Section 5.2.2 of the Application describes the method of calculating the forecast peak day load, which is derived as the product of the forecast use per customer on the peak day and the estimated number of customers on that day. The forecast use per customer on the peak day is based on a regression analysis of the relationship between peak day use per customer and weather (temperature and wind). The regression uses historical data from the past 10 years to estimate the use per customer for weather conditions with a 1 in 20 probability of occurring in the test year. As noted by SaskEnergy, this is consistent with the design criteria used by gas utilities elsewhere.

SaskEnergy notes that its peak day forecasting methodology was revised for the 2000/01 test year as its previous method was generating peak day design forecasts that were unrealistically high compared to the actual peak day loads experienced in recent years. For the past four years, the forecast of the peak day load was higher than the actual load adjusted for peak day conditions by a margin of seven to 10 percent. (For reasons discussed below, the forecast peak day load for 1996 was slightly lower than the actual peak day load and approximately 6 percent lower than the actual heating load adjusted to peak day design criteria.) Based on its revised methodology, SaskEnergy's forecast peak day load is lower than the forecast peak day load for the previous four years and is approximately 4 percent higher than the actual 1999 peak day load adjusted to peak day design criteria.

SaskEnergy has explained that the current peak day methodology uses both degree-day and wind-chill criteria as design conditions in its analysis, whereas the former analysis used only wind-chill data. With the change to the use of both degree-day and wind-chill data, the design conditions were revised to be 56 degree-days (equivalent to an average daily temperature of minus 38 degrees Celsius) and a wind-chill factor of 2421 watts per square meter, based on actual peak day conditions over the past 20 years. Finally, SaskEnergy has indicated that after extensive review and analysis it concluded that the peak day data for the 1995/96 heating season represents an anomaly and is unrepresentative of actual conditions on the day. Consequently data representing that peak day have been excluded from the analysis.

2.3 BCUC Staff Assessment

Generally, BCUC staff find the annual load forecast for all customer categories, except that of the farm forecast, to be reasonable. The farm use data filed suggests that the assumed use per account value of 139 GJ/yr is still too low, even after accounting for the reclassification of some farm accounts. Consequently, BCUC staff recommend that the assumption for farm use per account be increased to 158 GJ/yr and the forecast sales volume for farm sales be increased to 3,601 TJ/yr. This would increase the farm load for the 2000/01 gas contract year by 439 TJ and the total load forecast to 66,929 (excluding unmetered consumption and internal usage). This change would have the impact of reducing average rates by less than 1 percent, and is equivalent to a revenue requirements reduction of $1.091 million.

An adjustment to the methodology to prevent peak day forecasts that are too high prevents overspending on facilities related to gas supply and gas transmission and distribution capacity. However, the revision to the methodology must be carefully tested and monitored to avoid undue risk of generating forecasts that are too low, resulting in the prospect of higher costs due to greater than anticipated purchases of spot or peaking gas or curtailments. The level of risk that SaskEnergy should be prepared to accept in its peak day forecasts should be related to the costs associated with forecasts that are either too high or too low. With those caveats in mind, it appears that SaskEnergy has undertaken a thorough analysis with respect to revising its peak day forecasting methodology. Consequently, the design peak day forecast appears reasonable, and should be accepted.

3.0 OPERATING EXPENSES AND MISCELLANEOUS REVENUE

3.1 Operating, Maintenance and General Expenses

The total operating, maintenance and general expenses ("O&M"), net of allocations and capitalization, are forecast to increase to $70 million in the 2000/01 test year compared to $63.4 million in the 1999 business plan and $64 million that were actually incurred in 1999. Allocations and capitalization of O&M will be addressed in Section 3.2.

The proposed increase in O&M of approximately from 1999 actual to 2000/01 is mainly comprised of a increase in labour costs, a expense due to the use of non-temperature compensating meters and a in the amount of O&M expenses that are transferred to plant additions or external recoveries. In evaluating the forecast level of O&M for 2000/01, the actual 1999 O&M levels were considered and the impacts that customer growth, inflation and productivity should have on O&M from 1999 to 2000/01.

The Utility identified the actual salaries, wages and benefits for 1999 and the forecast for 2000/01. The proposed increases for 2000/01 exceed a 2 percent per year inflation forecast for the 22 months from the end of 1999. The executive salaries are shown as increasing by from 1999 actual to the forecast for 2000/01. With an inflation forecast of 2 percent for 2000/01, a provision to increase the executive salaries by 4 percent for the 22 months from the end of 1999 to 2000/01 should be sufficient. The reduction to executive salaries would be approximately $36,000.

All other wages and salaries are forecast to increase by approximately from 1999 actual to the forecast for the 2000/01 test year. This increase is partly explained by increasing the number of employees. If all other wages and salaries were adjusted to allow for an annual 2 percent inflation increase on the wages per employee for 22 months, the provision for non-executive wages and salaries would be reduced by $1,654,000.

The average cost of benefits, per employee, is shown as increasing by from 1999 actual to the forecast for 2000/01. Increases in Employment Insurance and Canada Pension Plan contributions may explain some of the increases. A maternity benefit plan was started in 1998 and the 1998 increase in the employer share of employee contributions under the Superannuation plan should already be reflected in the 1999 actual. The 2000/01 average costs of benefits should be the 1999 actual level. This would allow for a reduction of $392,000.

The proposed reductions shown above to executive salaries, all other wages and salaries and the average cost of benefits would reduce the O&M before allocations and capitalization by $2,082,000.

To confirm the reasonableness of the specific O&M reductions, the level of overall O&M increase forecast for 2000/01 can be compared to the actual O&M results in 1999. The actual 1999 O&M per customer can be escalated to 2000/01 by allowing for customer growth and inflation less a productivity improvement factor. In negotiated settlement agreements reached between British Columbia utilities and their customer groups, the British Columbia Utilities Commission has approved multi-year, performance based settlement agreements that included productivity improvement factors ranging from zero percent to 4 percent with the most common factors being 1 percent and 2 percent.

On a formula basis of O&M per customer, the allowed O&M for 2000/01 can be calculated with an inflation allowance of 2 percent and productivity factors of 1 percent or 2 percent for the 22 months from the end of 1999 to the 2000/01 test year. The growth is represented by the increase in the average number of customers from 1999 actual to 2000/01. The 2000/01 O&M forecast should also include a provision for $1.157 million of non-temperature compensated meter expense that was not part of the 1999 actual.

On a formula basis of O&M per customer, the allowed O&M for 2000/01 could be:

	1999 Actual	2000/2001 (1% productivity)	2000/2001 (2% productivity)
Actual O&M	$64,032,000		
Average Customers	311,115	318,456	318,456
O&M/customer	$206	$206	$206
Inflation		2%	2%
Productivity		(1%)	(2%)
Allowed O&M – rounded		$66,810,000[1]	$65,602,000[2]
Plus: non-temperature compensated meters		1,157,000	1,157,000
Total Allowed O&M		$67,967,000	$66,759,000
Requested O&M		$70,081,000	$70,081,000
Reduction to O&M		$ 2,114,000	$ 3,322,000

Note 1: 318,456*$206*(1+((0.02-0.01)*10/12))*(1+(0.02-0.01))
Note 2: 318,456*$206*(1+((0.02-0.02)*10/12))*(1+(0.02-0.02))

The formula calculation indicates that O&M could be reduced by $2,114,000 if a 1 percent productivity factor were used and by $3,322,000 if a 2 percent productivity factor were used. These reductions are modestly higher than the specific reductions of $2,082,000 identified by BCUC staff. BCUC staff consider that the reduction to requested O&M should be $2,114,000 which recognizes the level of efficiency that SaskEnergy was able to achieve in 1999, adjusted for customer growth, inflation and 1 percent productivity. Given the limited data base and the constraints of the analysis, BCUC staff believe that this proposed reduction to O&M is reasonable for SaskEnergy to operate within and fair to the ratepayers of the Utility.

3.2 Operating and Maintenance Allocation and Capitalization

SaskEnergy allocates a portion of its O&M expenses to internal recoveries such as the gas supply function, external recoveries and the capitalization of O&M in the construction of additions to plant in service. The O&M allocation, capitalization and the expense adjustment for 2000/01 from Section 3.1, are summarized in Appendix 1.

SaskEnergy states that its allocations to subsidiaries and non-utility operations are at full cost but has no written corporate policy on the allocation of O&M to subsidiaries, commodity service and non-utility operations. The methods of allocating costs from SaskEnergy to its subsidiaries, are primarily based on an estimate of the time that will be spent providing services to the subsidiaries in the upcoming year. Other allocation techniques include specific identification such as software rental fees, kilometers of pipeline and the categorization of certain cost centres in the Utility such as the Human Resources cost centre as being corporate in nature. The cost of corporate cost centres is allocated to the Utility and subsidiary companies based on the number of employees in each of the entities. The allocations to subsidiaries are forecast to be $5.438 million in 2000/01 compared to actual 1999 allocations of $4.967 million.

Certain O&M costs are allocated to the commodity cost based on the estimated direct costs within the gas supply department, legal, corporate affairs, gas accounting areas, and a share of corporate overheads. The allocation of O&M to non-utility operations is based on an estimate of the time needed for the administration of brokering, contract industrial activities and the time attributed to service offerings such as non-safety service calls and appliance checkups. The allocations to commodity service are forecast at $1.684 million in 2000/01, compared to $1.186 million in 1999 actual. The allocations to non-utility operations, are forecast at $0.794 million in 2000/01 with no allocations in prior years. BCUC staff consider that the allocations of O&M to internal recoveries and external recoveries are reasonable.

The allocations to subsidiaries and non-utility operations could be more fully reviewed in a shared-services study. A shared-services study could also examine the use of corporate assets in providing services to subsidiaries and non-utility operations. It may be appropriate to allocate a portion of the investment in corporate assets and the related depreciation expense to subsidiaries and non-utility operations to reflect the services provided. However, the current allocations based on an estimate of time that will be spent on the service provided are acceptable.

The amount of O&M costs that are charged to capital additions is forecast to be $11.033 million in 2000/01, compared to $12.557 million in actual 1999. The forecast additions to plant in service are shown as $42.122 million in 2000/01, compared to $40.796 million in 1999. The ratio of O&M costs capitalized to the total cost of capital additions is 26.2 percent in 2000/01 and 30.8 percent in 1999 actual. The O&M capitalization percentage remains very high.

BCUC staff have not adjusted the O&M allocations to capital or the allocations to subsidiaries, non-utility operations and commodity service. The allocations are not unreasonable and the level of information available is insufficient to allow a detailed analysis of the prudency of the allocation policies and accounting. BCUC staff recommend that SaskEnergy develop a Code of Conduct and Shared Cost Allocation Policy, governing cost allocations and transfer pricing between the Utility and its subsidiaries. An approved policy will simplify the review of future allocations and provide the basis for assuring the public that the Utility is not subsidizing other operations.

3.3 Delivery Transportation and Storage Expense

SaskEnergy's Delivery Rates include the cost of TransGas service to transport gas from TEP, the notional interchange point, to the town border stations. The Delivery Rates also include the cost of TransGas storage, which SaskEnergy uses to store gas in the summer for withdrawal in the winter. Current TransGas rates were approved by the Saskatchewan Cabinet, and came into effect January 1, 1999. The level of TransGas rates are outside the scope of this Report, and a review of the rates would require an analysis of TransGas costs, revenue and loads.

Forecast transportation costs of $37.002 million are approximately $1.7 million below 1999 actual costs. This is due to lower overall levels of service required by SaskEnergy, consistent with its reduced design peak day forecast and the load forecast for the year. The forecast storage cost of $12.674 million is approximately equal to the 1999 actual costs. BCUC staff have not identified any issues with these forecast costs.

3.4 Distribution Toll Revenue

Distribution customers who purchase gas directly from a supplier and contract directly with TransGas for transportation, require the use of the SaskEnergy distribution system to deliver the gas to their facilities. These are mainly industrial class customers. SaskEnergy recovers revenue for the use of its system from TransGas, and forecasts that revenue will increase by $840,000 from 1999 actual, to $8.412 million for 2000/01. SaskEnergy indicates that proposed changes to the Distribution Tolls contribute $242,000 of the increase, and higher gas volumes to large industrial customers account for the remainder.

SaskEnergy states that Distribution Tolls are determined in conjunction with Delivery Rates, using the same rate design study. The tolls are considered to be an internal cost allocation. As such, they are not approved by the Saskatchewan Cabinet, or included in SaskEnergy's published tariff.

Usually, to deal with a revenue deficiency or surplus, distribution tolls such as these would be adjusted pro rata with other delivery rates. BCUC staff note that the average rate for 2000/01 deliveries of $0.1234/GJ ($0.0046 per cubic metre) appears relatively low. However, considering the amount of Distribution Toll revenue forecast for 2000/01 and recognizing that the cost of service methodology and study that allocates costs between rate classes is outside the scope of this review, BCUC staff accept the forecast.

SaskEnergy also serves contract industrial customers. Small contract industrials are considered to be delivery service customers, and revenue from them is reported on Schedule 2.4 of the Delivery Rate Application. The $636,000 of Distribution Toll revenue forecast from the medium and large contract industrials is reported as part of Other Revenue on Schedule 1.6 of the Application.

3.5 Other Revenue

Other Revenue includes Amortization of Customer Capital Contributions, which is projected to increase consistent with higher customer contributions for service extensions in 2000/01. Connect Fees are forecast to be relatively stable, while Late Payment Charges have shown a modest downward trend. Some other activities like Customer Financing have been moved to non-utility operations, along with the cost of conducting this business.

The Margin on Competitive Gas Sales has declined from a 1999 Budget of $1,172,000 and 1999 actual of $2,153,000 to a forecast of $1,337,000 for 2000/01. This forecast includes $636,000 of Distribution Toll revenue from medium and large contract industrials. Competition has reduced the margins that can be charged, and SaskEnergy has allocated $300,000 O&M expense to this activity. The Utility proposes that the remaining $401,000 be shared 50/50 between customers and non-utility operations. SaskEnergy considers that uncertainty in the revenue forecast supports the proposed sharing.

It is becoming more common for utility regulators to support financial incentives that encourage innovation and superior performance when a utility participates in competitive activities, and when it appears likely that utility customers will realize a benefit overall. In this particular case, it is not clear what Utility resources are being used to make the sales, what SaskEnergy non-utility operations contribute to earn a share of the margin, or how performance will be measured. Also, a high sharing percentage to non-utility operations is a concern, as it may unduly bias the allocation of resources.

BCUC staff note that SaskEnergy is providing gas supply management services to Swan Valley. Considering this potential additional revenue and the forecast reduction in Margin on Competitive Sales revenue since 1999 actual, BCUC staff consider that all of the forecast revenue should be returned to customers. That is, Other Revenue for 2000/01, as revised to $4.169 million by SaskEnergy's

November 7, 2000 Revised Information Response 6.3, should be increased by $201,000 to $4.370 million. In its next rate application, SaskEnergy should support its request for an incentive with an analysis of the effect of the arrangement on Utility customers. An ideal mechanism would incent SaskEnergy to maximize revenue from competitive sales and share revenue with ratepayers in a proportion which ensures ratepayers receive more benefit than if an incentive was not paid.

4.0 RATE BASE AND RELATED CHARGES

4.1 Additions to Rate Base and Average Rate Base

Rate base for 2000/01 is forecast at $444.7 million and is comprised of plant in service, customer contributions towards the cost of capital additions, natural gas in storage, inventories of materials and a cash working capital allowance.

The Terms of Reference established that the amounts shown as rate base in 2000/01 were to be taken as given. During the BCUC staff review of the Delivery Rate Application and Commodity Rate Application, the following items were discovered regarding rate base treatment and are included for information purposes.

The plant in service investment at cost, less the accumulated depreciation and customer capital contributions, are included in rate base as the average of the opening and closing balances on November 1, 2000 and October 31, 2001. Using the mid-year basis to establish the net plant in service in rate base is appropriate if the majority of plant additions occur evenly throughout the year. However, SaskEnergy installs mains and service line extensions primarily in the September to November time period due to customer demand. Similarly, a new office is under construction that has an estimated completion date of October 1, 2001. For significant plant additions such as the office building that are not placed into service around the mid-year point of May 1, 2001, the rate base impact of the addition is overstated by using a mid-year average.

The rate base impact of significant plant additions such as the office building and recurring additions such as mains and service line extensions that do not occur evenly throughout the year are more appropriately represented by a 13-month average calculation of the cost of those additions. SaskEnergy has calculated that the use of a 13-month average would reduce the plant in service investment in rate base to $442.2 million. Commission staff consider that the rate base could be reduced to $442.2 million to reflect the 13-month average impact.

The monthly average investment in natural gas in storage has been forecast by SaskEnergy and included in rate base at a value of $41.56 million. In the Delivery Rate Application, the 2000/01 return on rate base is shown on Schedule 1.5 as 9.1 percent and is described as excluding the carrying charges of gas in storage

balances and the interest charges arising from non-utility business activities. The effect of this adjustment to the rate of return on rate base, is to transfer out the interest portion of $2.871 million from the return on rate base but leaves the equity portion of the rate base return in the cost of service for delivery service. Considering the volatility in natural gas prices, the turnover in natural gas storage and the use of a Gas Cost Variance Account ("GCVA"), BCUC staff believe that a preferred regulatory treatment would be to remove the investment in natural gas in storage from rate base and include the carrying cost of the storage investment in the GCVA. This regulatory treatment is consistent with the description of the GCVA in Section 4.6 of the Commodity Rate Application, where the carrying cost of gas in storage is stated to be the short-term borrowing rate. If this adjustment is made, the rate base for 2000/01 would be reduced by $41.56 million and the equity return on the $41.56 million would be removed from the return on rate base as an estimated reduction of $1.119 million (($41,560,000 * 9.6%) – $2,871,000). The return on rate base including the interest and equity returns, is shown as 9.6 percent in SaskEnergy's November 2, 2000 Information Response 1.1.

BCUC staff have not identified any issues regarding the amounts included in rate base for customer capital contributions, inventory of materials and cash working capital allowance.

4.2 Capital Structure and Interest Costs

SaskEnergy has described the proposed capital structure for the 2000/01 test year as being comprised of 60 percent debt and 40 percent equity. However, information provided by SaskEnergy indicates an actual equity of about 25 percent. The debt components of capital structure are comprised of short-term and long-term debt with short-term debt having a forecast average embedded cost of 6.3 percent for 2000/01. The long-term debt has a forecast average embedded cost of 8.7 percent which results from about $112 million of long-term debt maturing in 2001 and new debt being issued at a forecast interest cost of 6.75 percent. A portion of the debt financing cost is allocated to the commodity cost of service as the financing cost of gas in storage. An additional allocation of debt costs is made to non-utility operations related to the customer financings that were recently transferred from utility operations to non-utility operations.

SaskEnergy has described the rate of return on common equity ("ROE") for 2000/01 as being forecast at 12 percent after tax. This conflicts with other information implying a 14 percent return at the reduced actual equity levels. The debt and equity components and their average costs are shown in the Delivery Rate Application as having a combined average cost of 9.1 percent. This combined average cost of debt and equity is also called the annual rate of return target which is multiplied by the rate base to determine the return on rate base that is included in the revenue requirement calculation.

The terms of reference established that the amounts shown as rate base in 2000/01 and the annual rate of return target are to be taken as given. However, the equity component and its assumed return, are abnormally high compared to those allowed for other natural gas utilities and pipelines in Canada. SaskEnergy is a low risk utility and the GCVA discussed in Chapter 6 will reduce risk further.

BCUC staff have reviewed the capital structures and returns of other low risk, natural gas utilities and pipelines in Canada and find that a typical capital structure would include 30 to 35 percent equity and awarded returns for 2001 are likely to range between 9.25 to 9.75 percent. Several of the other regulators have developed automatic annual adjustment mechanisms to set appropriate returns. Even without an increase in Delivery Rate revenue, SaskEnergy will be earning a significant return in 2000/01, compared to other low risk local distribution companies.

4.3 Depreciation

BCUC staff reviewed the depreciation rates used by SaskEnergy and compared the rates to those allowed for BC Gas Utility Ltd. ("BC Gas"). In some cases the depreciation rates employed by SaskEnergy were slightly higher or lower than those used by BC Gas. BCUC staff have not identified any issues regarding depreciation.

4.4 Corporate Capital Tax

Corporations with a permanent establishment in Saskatchewan are required to pay a tax on their paid up capital, if the paid up capital, less deductions, is greater than zero. The current tax rate is 3.25 percent for banks and loan and trust corporations and 0.6 percent for other corporations. BCUC staff reviewed the calculation of the corporation capital tax for 2000/01 and found the calculations to be reasonable.

5.0 DELIVERY RATES

5.1 Revenue Requirement and Revenue Deficiency

On Schedule 1.1 of the Delivery Rate Application, SaskEnergy summarized its revenue requirement for 2000/01. A cost of service of $178.625 million is forecast for 2000/01 which is reduced by other revenue of $3.851 million (subsequently revised to $4.169 million) and distribution tolls of $8.412 million to produce a forecast revenue requirement of $166.363 million. SaskEnergy determined that at present rates, it would generate revenue of $162.455 million and would experience a revenue shortfall of $3.908 million for 2000/01 as shown on Schedule 2.4. In order to recover the revenue shortfall, SaskEnergy requested that the current rates for delivery service be increased by 2.4 percent on average effective November 1, 2000.

SaskEnergy's November 7, 2000 Revised Information Response 6.3, revised the forecast other revenue resulting in a revenue shortfall of $3.589 million, as shown on Appendix 2.

BCUC staff reviewed the Delivery Rate Application and recommended some adjustments to the 2000/01 revenue requirements and revenue forecasts. O&M expenses were reduced by $2.114 million to reflect adjustments to labour forecasts as described in Sections 3.1 and 3.2. Other revenue was increased by $201,000 as described in Section 3.5. Forecast farm volumes were increased as described in Section 2.3. These adjustments are summarized in Appendix 2 and offset the forecasted revenue deficiency by $3.406 million to produce a 2000/01 revenue deficiency of $0.183 million or 0.11 percent based on current rates.

5.2 BCUC Staff Recommendation on Delivery Rates

Considering the small adjusted revenue deficiency for 2000/01, and the approximate nature of some of the proposed adjustments, BCUC staff recommend that current rates for delivery service remain unchanged for 2000/01.

SaskEnergy proposed passing through all of the Delivery Rate increases to the residential and farm consumers in the Basic Monthly Charge and to the commercial (General Service II and III) customers in the Delivery Charge. BCUC staff have not reviewed this aspect of the application in depth, but note that different methods of passing through the increase will tend to create different consumer incentives. A higher Basic Monthly Charge will tend to have a greater rate impact on small volume consumers within a rate class and a lesser impact on large volume consumers. Moreover, a larger basic monthly charge and a lower delivery charge will increase the incentive to consume more gas relative to a higher delivery charge. A higher monthly charge will also tend to discourage connection of new customers who anticipate low or seasonal use. Nevertheless, BCUC staff would consider such effects to be modest at this time, and have not identified any issues with respect to the proposed allocation of the revenue deficiency.

6.0 SUPPLY PORTFOLIO

Saskatchewan and SaskEnergy are in a favourable position to arrange a secure, flexible and relatively low cost supply of natural gas for consumers. Production within Saskatchewan exceeds consumption and several large transmission pipelines cross the province carrying mainly Alberta production to market. The Alberta Energy Company ("AECO") gas trading point in Alberta is very liquid, and provides a reliable market price reference point along with opportunities for financial price risk management activities. In this setting, SaskEnergy has very good access to natural gas at market prices. Moreover, these prices are expressed in Canadian dollars.

Perhaps most importantly, SaskEnergy has access to underground gas storage in old gas fields and caverns that are conveniently located close to its major markets. The Utility relies on storage gas to meet about two-thirds of its design peak day demand. Saskatchewan consumers benefit greatly from the available storage in proximity to load requirements.

6.1 Contracted Gas Supply

In Section 3 of the Commodity Rate Application, SaskEnergy forecasts annual sales of 64.6 PJ in 2000/01 and, including fuel requirements, projects it will purchase 65.3 PJ. The Utility also carefully monitors supply during the November through March winter period, when most gas is sold. To the extent the weather is colder than average and sales are higher, SaskEnergy will buy additional winter term or spot supply. If sales are lower, the Utility may sell the surplus in the marketplace or keep it in storage inventory.

As discussed in Chapter 2, the design peak day demand for SaskEnergy delivery service customers is 602,929 GJ per day. A small portion is provided by customers that buy gas directly from suppliers. SaskEnergy relies mainly on storage gas and gas purchase contracts to supply daily sales demand, and anticipates buying a small amount of winter term or spot gas to handle very cold weather. With ready access to liquid gas markets, such gas should be available for purchase when needed, although the price may be high. SaskEnergy has considered the risks and potential costs and benefits, and will continue to evaluate its supply position on a go-forward basis.

SaskEnergy's supply portfolio for 2000/01 contains more than 40 gas purchase contracts. The Utility has provided BCUC staff with the critical information related to each contract, including purchase quantity and pricing terms. Similar detailed information has been provided about each financial price risk management arrangement that SaskEnergy has entered into for 2000/01. BCUC staff have assessed this information, and consider there is no need to examine the individual contract documents.

Only a relatively small amount of gas supply is newly contracted each year. SaskEnergy buys most gas under year-round contracts. The portion of total purchases that the Utility expects to acquire in Saskatchewan has increased to about 96 percent for 2000/01, as current market price differentials favour this shift.

SaskEnergy's gas purchase contracts generally have annual price reopeners. A small number of contracts have fixed pricing, while prices in most contracts are referenced to the AECO monthly index. Natural gas price differentials for deliveries at the Saskatchewan field points and at the TEP interchange point relative to the AECO index, are established by the marketplace through negotiation and reflect supply and demand considerations. SaskEnergy is very active in the marketplace and follows these price differentials closely.

6.2 Price Risk Management

In previous years, SaskEnergy established its Gas Consumption Charge as a gas sales rate that was fixed for one year. Unlike several other gas utilities in Canada, it did not have a gas cost variance account in which to record differences between forecast and actual gas costs. To reduce the price risk from its AECO index-based purchases, the Utility used financial instruments to convert most of its index-based purchases to fixed pricing. SaskEnergy also purchased call options, which limited its upward cost exposure, but enabled it to benefit when market prices were lower. SaskEnergy's strategy was to implement its price risk management strategy in advance of the start of the gas year. The Utility established a fixed price for its gas purchases that reflected the average of the market price expectations, and which was the basis for the fixed gas commodity rate for the year.

Natural gas prices for 2000/01 have been trading at record high price levels in Western Canada and across North America. High crude oil prices have caused some switching from fuel oil to natural gas. Increased gas demand for gas-fired electrical generation in the summer competed with the need to refill gas storage, and storage levels in the United States are lower than they were a year ago. High gas and oil prices have generated a strong increase in the number of wells that producers are drilling in Western Canada and the United States, but this has not yet resulted in a material increase in gas production. SaskEnergy expects that prices this winter will be strongly influenced by the weather, and could increase or decrease significantly from present levels.

SaskEnergy has fixed the price of a portion of the gas in its portfolio for 2000/01, and has entered into some option arrangements. These activities plus the gas that is in storage has secured a considerable portion of supply for 2000/01 at prices that are well below current market prices. However, due to the present very high price levels and extreme price volatility, SaskEnergy has maintained a significant portion of its portfolio with indexed prices. The price for this gas will float with the market. SaskEnergy anticipates that, in the event recent forecasts of a relatively mild winter come about, the result will be lower market prices and lower actual gas costs.

6.3 Gas Cost Variance Account

The actual cost of gas can vary from forecast for a number of reasons, of which two are particularly significant. First, gas that does not have a fixed price will be bought at actual market price at the time of purchase. Second, load variations caused by weather will affect the proportions of purchased and storage gas supply that is sold. Most gas utilities in Canada have a deferral account in which to record differences between actual and forecast gas costs. SaskEnergy's Board of Directors on August 11, 2000, approved a Gas Cost Variance Account to be effective November 1, 1999.

Purpose of the GCVA

Sections 1.8 and 4.6 of the Commodity Rate Application describe the GCVA, and state that the account is intended to reconcile any differences between the actual and forecast cost of gas. However, the GCVA as currently structured does not record the difference between the actual and forecast cost of gas, but instead records the actual commodity cost of gas compared to actual commodity revenue from sales of gas. The GCVA is compensating not only for differences between the actual cost of gas and the forecast cost that is embedded in the rates, but also for differences in the volume of sales. BCUC staff consider that this form of deferral account is justified in order that SaskEnergy fully recovers its prudently incurred actual costs of providing the gas commodity to customers, without a mark-up. With the GCVA, the Utility does not gain or lose from its commodity sales business.

Structure of the GCVA

The actual commodity cost of gas recorded in the GCVA will include all cost items in the Commodity Rate Application. Commodity revenue will include actual commodity revenue from the Gas Consumption Charge, revenue from excess gas sales and late payment charges. The account balance attracts interest at SaskEnergy's short-term borrowing rate.

At the end of March each year, SaskEnergy will review the balance in the GCVA. If the account balance is a credit to customers of $10 million or more on or after March 31, SaskEnergy could take action to return the balance to customers. If the March 31 balance is a deficit of $10 million or more, SaskEnergy will apply for an upward rate adjustment. If a $10 million balance owing to SaskEnergy accumulates prior to March 31, the Utility could also apply for a rate increase at that time.

The structure and operation of the account generally appears to be reasonable. An account balance of $10 million seems to be a reasonable criterion for action to remedy the balance. However, given the current volatility in gas prices, it is a relatively sensitive measure, and BCUC staff encourage the parties to view a $10 million balance as indicating the need for a review of the situation, rather than an absolute requirement for action. Conclusions about the need for rate changes should be based on a broad assessment of circumstances at the time. Also, SaskEnergy may wish to consider the use of a rate rider to deal with GCVA balances, to identify and account for separately the effect of these balances on customer rates.

BCUC staff believe that variances in costs that are considered to be controllable by the Utility should not be recorded in the GCVA. Other Operating Expenses include direct expenses, corporate overhead, depreciation, bad debt costs and late payment charges that are related to the gas supply activity. It is reasonable to include these forecast costs in the Gas Consumption Charge. However, like similar costs

that are recovered in Delivery Rates, these costs are to be controllable and BCUC staff consider it inappropriate for SaskEnergy to recover variances from the forecast that was used in the setting of rates. If the Utility were not held responsible for costs within its control, no cost discipline would exist. The amount of interest charges on gas storage inventory largely depends on factors that are not within the Utility's control, and so actual interest charges should be recorded in the GCVA. Also, actual interest costs should apply to the positive or negative balance in the GCVA.

GCVA Balance to October 31, 2000

In the Commodity Rate Application, SaskEnergy projected a credit balance of $156,000 to October 31, 2000 and used the amount to reduce the forecast Cost of Gas Sold for 2000/01. No interest was charged or credited in 1999/2000. BCUC staff do not object to the absence of interest in the start-up year, as account balances were reasonably small during the year, and were both positive and negative.

SaskEnergy recorded $2.321 million of Other Operating Expenses in the GCVA in 1999/2000, and separately recorded $353,000 of late payment charges as a credit. Also, the $2.321 million includes $504,000 of summer use storage costs. Although a regulatory practices purist might consider that all storage costs are to be recovered in the Delivery Rates, the summer use storage costs were incurred to reduce gas commodity costs and BCUC staff consider fairness requires that they be recovered in the Gas Consumption Charge. On this basis, the net amount of Other Operating Expenses recorded in the GCVA was $1.464 million. As reported on page 19 of the Commodity Rate Application, rates for 1999/2000 include non-interest Other Operating Expenses of $1.455 million. BCUC staff consider that the difference does not warrant an adjustment.

Also, 1999/2000 rates excluded $1,375,000 of interest costs related to gas in storage, on the basis that the interest cost was also in the Delivery Rates and the Utility was not entitled to recover the amount twice. The Utility has recorded $1,516,000 of storage inventory interest charges for 1999/2000 in the GCVA. Recognizing that SaskEnergy established the GCVA of its own accord without compensating for the interest cost embedded in 1999/2000 Delivery Rates, BCUC staff consider that storage inventory interest charges need to be removed from the GCVA for 1999/2000. The reason for excluding the interest charge from 1999/2000 rates continues to be valid, and the GCVA credit balance to October 31, 2000 should be increased from $156,000 to $1,672,000. In future, it will be appropriate to record such interest charges in the GCVA, assuming storage inventory interest charges are removed from Delivery Rates.

6.4 BCUC Staff Assessment

SaskEnergy has developed a supply portfolio for 2000/01 that seems appropriate to meet the needs of its customers at the lowest overall cost, considering its location and the opportunities available. Although the analysis that established the detailed makeup of the portfolio has not been reviewed, it is felt that such

further review is not warranted. The arrangements that are in place for 2000/01 appear reasonable and the Utility is in the best position to optimize its portfolio. A regulator should not want to intrude on a utility's management function beyond what is necessary to assure the public that efficient operations exist.

The negotiated prices for the great majority of gas purchase contracts rely on the AECO index, which is a reliable indicator of market prices. The basis differentials relative to this index seem reasonable and there is no reason to believe that SaskEnergy is overpaying, when one recognizes that the results of negotiations can be expected to display a range of results and that market-based differentials change over time. It is also noted that the average cost of gas under the fixed price contracts is comparable to the fixed prices obtained through financial hedges.

SaskEnergy's past strategy of fixing the price of a very large portion of its purchases, significantly reduced the cost of gas to its customers over the past several years. However, given the current extremely high price levels and volatility, the Utility's reluctance to fully commit to these higher prices is understandable. The Utility's price risk management actions for 2000/01 have resulted in significant amounts of both indexed and fixed price supply in its portfolio, some financial options, and storage gas which acts as a fixed price supply. BCUC staff have not identified any issues about SaskEnergy's supply portfolio, supply contracting practices or price risk management activities for 2000/01.

As discussed in the preceding Section, BCUC staff generally accept the structure of the GCVA as introduced by SaskEnergy. SaskEnergy will have a reasonable amount of discretion as to the action it takes in response to balances in the GCVA. The $10 million criterion should be considered to indicate the need for a review of the situation, rather than an absolute requirement for action. Nevertheless, the Utility should be required to formally advise the Panel of the account balance to March 31 each year, and any actions that it proposes to take as a result.

The GCVA credit balance to October 31, 2000 should be increased from $156,000 to $1,672,000.

7.0 FORECAST COST OF GAS

The sales load forecast under average weather conditions and the portfolio of gas purchase contracts have been reviewed in earlier Chapters. This Chapter reviews the corresponding forecast 2000/01 Cost of Gas Sold of $292,076,000, set out in Sections 1 and 2 of the Commodity Rate Application. Appendix 3

compares the forecast for 2000/01 to the forecast for 1999/2000 that was the basis for current rates and to actual/projected numbers for 1999/2000. SaskEnergy has requested that detailed proprietary information about its supply arrangements be kept confidential, as disclosure would disadvantage the Utility and its customers. This request for confidentiality of commercially sensitive information is consistent with other provinces where commodity competition exists.

7.1 Cost of Gas Purchases

Fixed Price Contracts

The price under each contract is known for the forecast period. BCUC staff have checked the forecast cost of this type of supply and consider that the most current contract information would support a modest upward adjustment to the forecast Cost of Gas Sold.

Fixed Hedges and Price Differentials to AECO

For 2000/01, SaskEnergy has used financial instruments to convert a portion of AECO pricing to fixed prices. Although a full review of SaskEnergy's price risk management practices is outside the scope of this Report, BCUC staff have checked that the forecast for this component of cost of gas is consistent with the contractual information.

Most of SaskEnergy's gas purchase contracts have pricing that is referenced to AECO, plus a negotiated basis differential to adjust the price to the actual point of receipt of the gas. SaskEnergy calculates the total dollar amount of this component of the cost of gas. The information in the Application was prepared prior to finalizing prices under many contracts, and a calculation using the most current contract information indicates an adjustment that would significantly increase the forecast Cost of Gas Sold.

Exposed Gas and Options

Exposed gas is the gas that SaskEnergy expects to buy at current market prices, and which it has not hedged. There is risk in any price forecast for this supply, particularly in this period of extremely volatile market prices. Gas prices increased strongly after SaskEnergy prepared the forecast in the Application, and more recently have declined somewhat back towards the numbers in the Application.

For a portion of the gas purchases with AECO pricing, as an alternative to financially fixing prices, SaskEnergy has acquired options to limit the cost exposure if prices increase further, while providing some opportunity for cost savings if market prices decline. A review of these arrangements based on current market conditions indicates an upward adjustment to the Cost of Gas Sold.

SaskEnergy recalculated the Cost of Gas Sold using forward market prices as of October 20, 2000, and estimated that the forecast Cost of Gas Sold for 2000/01 would increase by $17.9 million to $310.0 million. The Utility also recalculated the Cost of Gas Sold using the lower October 25, 2000 forward prices, resulting in a figure of $303.4 million. Unfortunately, as of early November when this Report is being finalized, forward prices have increased back to October 20, 2000 levels.

7.2 Transportation Costs

SaskEnergy has contracted for TransCanada Alberta (previously Nova Gas Transmission Division) transportation service to the Saskatchewan border, and pays rates approved by the Alberta Energy and Utilities Board for the capacity. The amount of gas that SaskEnergy purchases in Alberta has declined, but the TransCanada Alberta capacity is under a long term contract that cannot be reduced until the end of this year. The expiry of the contract will permit SaskEnergy to review the amount of TransCanada Alberta capacity that it needs.

SaskEnergy also contracts TransGas transportation capacity for moving gas to the TEP interchange point from Saskatchewan field receipt points or interconnects at the Saskatchewan/Alberta border. SaskEnergy pays for the capacity at TransGas' current published tariff rates, which have been approved by the Saskatchewan Cabinet and went into effect January 1, 1999. An assessment of the level of current TransGas rates is outside the scope of this Report.

The Utility has reduced the amount of TransGas capacity it contracted for 2000/01. SaskEnergy has enough capacity for the volume of gas it receives at Saskatchewan field receipt points and buys in Alberta, plus an amount equivalent to the TransCanada Alberta surplus capacity that it has. The capacity serves a useful backstopping role, as it provides SaskEnergy with firm access to the large Alberta supply pool, and is sufficient for the winter term or spot gas the Utility may need to buy if the winter is very cold. SaskEnergy appears to be carefully managing the amount of transportation that it contracts for.

SaskEnergy also pays transportation charges to suppliers for gas that is priced in the field, but which the supplier transports to the TEP interconnect point. The amount of this gas has increased for 2000/01, and accounts in part for the reduction in the amount of TransGas transportation capacity that SaskEnergy holds. Nevertheless, a review of the amount of these payments in the Application supports a significant downward adjustment to the total Transportation Charges, which would reduce the $13.48 million forecast cost to somewhat below the 1999 actual cost of $11.58 million.

Like most gas utilities, SaskEnergy uses surplus capacity to make sales or transport gas for others, to generate revenue that can be used to offset costs. SaskEnergy uses such revenue to reduce Delivery Rates rather than the Gas Consumption Charge, as it considers that use of the pipeline capacity depends, in part, on access to storage, which is charged to all customers. In principle, it would seem more fair to allocate

part of the revenue to offset gas costs. In practice, it is recognized that this source of revenue is uncertain and difficult to predict, and may generally be relatively small, so that crediting it to Delivery Rates seems reasonable.

7.3 Change in Storage Inventory Value

Gas injected into storage is valued at the average cost of acquiring the gas that month at the TEP interchange point. This cost includes the gas purchase cost including hedging effects and the cost of transportation to TEP. Gas withdrawn from storage is priced at the average cost of gas in inventory.

As the 1999/2000 winter was relatively mild, SaskEnergy was left with about 10 PJ of gas in storage, which reduced the amount of gas to be injected during summer 2000. The Utility sold excess supply into the marketplace during the summer, and credited the revenue to customers via the GCVA. SaskEnergy deemed that the cost of the gas sold was the average cost of gas in storage at the end of winter, rather than the cost of gas purchased each month, as it considered that it was selling surplus storage inventory from the winter. BCUC staff are concerned that the deemed cost was not consistent with the average cost of gas methodology that the Utility uses for storage inventory. Also, the cost of gas purchased each month would seem to be a better basis for making decisions about surplus gas sales. Nevertheless, the use of a deemed price for the surplus sales will not have a material effect on rates for 2000/01, and therefore no adjustment is required.

The expected higher price of gas to be stored in the summer of 2001 means that the value of gas in storage is anticipated to increase significantly over the gas year. This results in a reduction in the gas costs to be recovered from customers in 2000/01. This benefit has been appropriately recognized by SaskEnergy in its Application.

7.4 Internal SaskEnergy Usage

SaskEnergy uses some gas for the operation of its distribution system. It buys this gas as part of its supply procurement, and recovers the cost of the gas through its Delivery Rates. The cost of Internal Usage gas is deducted from the cost of gas, with the credit calculated at the average cost of gas, including transportation to the TEP interchange point.

For 2000/01, SaskEnergy has included 259,000 GJ of gas valued at $1,157,000 as an allowance for Lost and Unaccounted For Gas. The allowance is 0.4 percent of sales, and is needed as SaskEnergy still has a considerable number of non-temperature compensated meters in its system. The amount of Lost and Unaccounted For Gas will decline as these meters are replaced over the next several years.

The forecast Internal Usage cost of $2,115,500 is acceptable.

7.5 Other Operating Expenses

In order to maintain an equitable balance of costs between Utility sales and delivery service for directly purchased gas, SaskEnergy includes costs that are related to gas procurement and management in the commodity cost of gas. For 2000/01, these costs are forecast as follows:

Gas Supply, Legal, and Accounting Expenses	$ 801,000
Corporate Overhead	262,000
Depreciation and Corporate Capital Tax	250,000
Net Bad Debt Expense/Late Payment Charges	(356,000)
Other Interest	40,000
Total Non-Storage Interest	997,000
Interest on Gas in Storage	2,738,300
Total	**$3,735,300**

Excluding interest charges on gas in storage, the forecast total of $997,000 is lower than the corresponding projected 1999/2000 amount of $1,464,000, due to the larger amount of Late Payment Charges that are forecast for 2000/01. BCUC staff support including these costs in the Gas Consumption Charge for Utility sales customers, to ensure that the Utility competes fairly with other gas marketers. However, as discussed in Section 6.4, the non-storage interest component of $997,000 consists of items that are generally considered to be controllable by the Utility, and SaskEnergy should not record variances from this amount in the GCVA.

Assuming that carrying charges for the cost of gas in storage are removed from Delivery Rates, it is appropriate to include forecast storage inventory interest costs in the calculation of the Gas Consumption Charge, and to record the actual interest costs in the GCVA.

7.6 Swan Valley Gas Corporation

SaskEnergy recently established a subsidiary, Swan Valley Gas Corporation ("Swan Valley"), to serve about 1,000 customers in Manitoba, including one industrial customer. Swan Valley has contracts with SaskEnergy and other affiliated companies for the provision of management services, gas supply, storage and transportation. Service to a limited number of customers is expected to commence around mid-December 2000, with more customers added as the year progresses. Swan Valley customers are forecast to consume about 6 TJ up to the end of March 2001, and a total of 25 TJ in 2000/01.

Swan Valley will obtain gas for its customers from SaskEnergy's supply portfolio. The gas will be priced at SaskEnergy's Gas Consumption Charge plus an allocation of SaskEnergy's storage costs. The storage

costs paid by Swan Valley will be credited to SaskEnergy's revenue requirement for Delivery Rates. The amount of allocable storage costs is forecast at $3,000 for 2000/01. SaskEnergy did not include a storage cost credit in the 2000/01 Delivery Rate Application, on the basis that delays in the in-service date make the forecast uncertain and that the forecast amount was not material.

SaskEnergy has allocated some management support costs to Swan Valley, and will bill for the direct cost of the services such as service technician time that it provides. SaskEnergy included $111,000 from Swan Valley in the Capitalized and Recovered credits on Schedule 1.3 of the Delivery Rate Application for 2000/01. It is not clear from the information whether all legal costs incurred in 1999 were properly allocated to Swan Valley, but BCUC staff note that those costs will not impact SaskEnergy's O&M allocations in 2000/01, in any event.

SaskEnergy appears to have provided a reasonable accounting and allocation of costs for Swan Valley. Proper allocation of costs within a utility and between a utility and its affiliates becomes more important as unbundling proceeds and the utility expands into non-regulated activities. Generally, transfer pricing for services provided to an affiliate should be charged at the higher of fully loaded cost or market value. (There can be exceptions in unusual circumstances. For example, it seems reasonable for Swan Valley to share SaskEnergy's supply portfolio on a long-term basis, as SaskEnergy proposes.) The development of the Code of Conduct and Shared Cost Allocation Policy, recommended in Section 3.2 of this Report, will assist the review of future subsidiary activities of SaskEnergy.

Due to the delays in bringing the Swan Valley system into service, the limited amount of gas sales that is forecast for 2000/01 and the amount of the credit included in the Delivery Rate Application, BCUC staff consider that the arrangements with Swan Valley are acceptable.

8.0 GAS CONSUMPTION CHARGE

8.1 Cost of Gas Sold

Chapter 7 discusses several adjustments that could be made to the forecast Cost of Gas Purchases and Transportation Cost set out in the Commodity Rate Application, to incorporate more current forward gas prices and more up-to-date contract information. Excluding changes that result from more current forward prices, the adjustments approximately offset one another. With the GCVA to record actual gas costs, there is much less need to make fine-tuning adjustments to the forecast Cost of Gas Sold. On the other hand, more scrutiny is required to ensure proper recording of actual costs and revenues in the GCVA, and SaskEnergy should anticipate detailed reviews and perhaps an audit of the account.

As gas prices and price expectations for 2000/01 are extremely volatile, it is very difficult to determine the best price forecast upon which to base the Gas Consumption Charge. SaskEnergy, the Panel and customers should anticipate that the commodity rate may need to change during the gas year. For example, using current forward prices in the calculation of Cost of Gas Sold would increase the forecast cost by about $18 million compared to the numbers in the Application. Conversely, if the Gas Consumption Charge is based on the forecast in the Application and actual gas prices turn out to be equal to current market expectations, a deficit balance of about $18 million will accumulate in the GCVA over the year. This can be compared to the $10 million criterion for the balance in the GCVA, and implies that an increase in the Gas Consumption Charge is likely to be needed for April 2001. On the other hand, lower actual market prices may permit a mid-year rate reduction.

In this situation, and with the hope that market prices will continue to soften as they did in October, BCUC staff consider that the adjusted Cost of Gas Sold in the Application of $291,920,000 should be accepted. This cost includes a GCVA credit to the end of October 2000 of $156,000, as reported in the Application and shown on Appendix 3.

In Chapter 2, BCUC staff recommend an upward adjustment to forecast sales to farm customers. This change would affect both the annual sales quantity and the amount of gas purchased that is used to calculate the Cost of Gas Sold. As both sales and gas costs would increase, the adjustment to forecast sales is relatively small, and any variances will be recorded in the GCVA, no adjustment to the Gas Consumption Charge calculation is recommended to reflect the increased forecast sales to farm customers.

SaskEnergy has good access to market-area storage that it uses to shape gas supply to the weather-dependent loads of its customers, and recovers the storage costs in its Delivery Rates. The Utility charges all classes of sales customers the same Gas Consumption Charge. Although rate structure is outside the scope of this Report, BCUC staff consider that a single gas commodity charge is reasonable in SaskEnergy's circumstances.

8.2 Delay of Rate Increase to December 1, 2000

It is apparent that new rates are unlikely to take effect before December 1, 2000. SaskEnergy estimates that a debit amount of $14.4 million will be recorded in the GCVA in November 2000. The adjusted GCVA credit balance to the end of October 2000 of $1.7 million will partially offset this debit.

Utility regulators have a responsibility to customers to ensure that utilities provide safe, reliable, low cost service. Equally, regulators have a responsibility to utility owners to set rates that will provide a reasonable opportunity to earn a fair return on their investment. While utilities have an onus to anticipate

cost increases, it is only fair to allow SaskEnergy to increase its rates consistent with the reasonable increase in its forecast cost of gas.

There is little benefit to setting rates for 2000/01 that are likely to cause GCVA balances to persist at the negative $10 million or greater level. Recognizing that the adjusted Cost of Gas Sold is somewhat low relative to current market prices, BCUC staff support a Gas Consumption Charge effective December 1, 2000 that will recover the gas commodity revenue deficiency for 2000/01 over sales in December 2000 through October 2001. Schedule 3.1 of the Commodity Rate Application shows 1,549.0 million cubic metres of sales over the 11-month period. As shown on Appendix 3, the resulting Gas Consumption Charge is $0.1741 per cubic metre. Although the GCVA balance is likely to exceed the $10 million criterion as of the end of November 2000, the situation should rectify itself over subsequent months, provided there is some downward movement in gas prices.

The resulting change in the Gas Consumption Charge is an increase of $0.0631 per cubic metre or 57 percent, effective December 1, 2000. The corresponding change in the annual bill of a typical residential customer for the full November 2000 through October 2001 gas year is an increase of $197, or 25.6 percent, as requested in SaskEnergy's Commodity Rate Application.

8.3 BCUC Staff Recommendations on Gas Consumption Charge

BCUC staff are of the opinion that the forecast set out in SaskEnergy's Commodity Rate Application and the rate derived from it are generally fair and reasonable, subject to the changes set out in the following Recommendation and on the understanding that the GCVA will be in effect.

Recommendation:

- Direct SaskEnergy to adjust the forecast GCVA balance to October 31, 2000 to a $1,672,000 customer credit, so as to remove the interest charge on Gas in Storage for 1999/2000;
- Direct SaskEnergy to use the adjusted Cost of Gas Sold in the Commodity Rate Application to recalculate the rate increase effective December 1, 2000, that will be required to recover the 2000/01 gas cost revenue deficiency over forecast deliveries in December 2000 through October 2001. The resulting Gas Consumption Charge is expected be about $0.1741 per cubic metre;
- Direct SaskEnergy to record its budgeted amount of non-storage interest Other Operating Expenses of $997,000 in the GCVA for 2000/01; and
- Direct SaskEnergy to formally advise the Panel of the GCVA balance to March 31 each year, and any actions that it proposes to take as a result.

9.0 OVERALL RATE IMPACT

SaskEnergy requested an increase in its Delivery Rates of 2.4 percent to recover its anticipated costs of operating the Utility delivery system. As described in Section 5.2, BCUC staff recommend that no increase be awarded. Anticipated costs increases and inflationary impacts can be offset by customer growth, productivity and other income.

The forecast increase in commodity costs are largely beyond the control of SaskEnergy and the Utility is doing an efficient job of mitigating costs during this period of high North American demand and constrained production capability. SaskEnergy requested a 50 percent increase in the Gas Consumption Charge effective November 1, 2000. The increase is not likely to be implemented until December 1, 2000 and SaskEnergy is likely to have additional unrecovered costs of $14.4 million in November. After adjusting the GCVA for interest charges on gas storage inventory for 1999/2000, the residual debit balance to November 30, 2000 will be approximately $12.7 million.

BCUC staff recommend that the gas commodity revenue deficiency, as forecast in the Commodity Rate Application, be recovered over the remaining 11 months of 2000/01, resulting in a Gas Consumption Charge of $0.1741 per cubic metre and a total commodity cost increase of 57 percent.

The total impact on customer rates of all recommended delivery charge and commodity rate changes is a $197 or 25.6 percent increase in the annual bill for a typical residential customer.

This Report is submitted as of November 20, 2000.

W.J. Grant, Executive Director

J.B. Williston, Manager
Engineering and Commodity Markets

J.W. Fraser, Manager
Strategic Services

P.W. Nakoneshny, Senior Financial Analyst
Rates and Finance

SaskEnergy Incorporated

2000/2001 Operating and Maintenance (in $ 000's)

Operations	2000/2001 Application	BCUC Adjustments	2000/2001 Adjusted
Costs Incurred	73,800		73,800
Capitalized and Recovered	(4,243)		(4,243)
Subtotal Operations	69,557		69,557
Engineering and Construction			
Costs Incurred	12,168		12,168
Capitalized and Recovered	(11,644)		(11,644)
Subtotal Engineering and Construction	524		524
Total Operating and Maintenance	**70,081**	**(2,114)**	**67,967**
Less: Allocation of Operating and Maintenance			
Allocated to Subsidiaries	(5,438)		(5,438)
Allocation to Commodity Service	(1,684)		(1,684)
Allocated to Non-Utility Operations	(794)		(794)
Allocated to Delivery Service	62,165	(2,114)	60,051

Source of Adjustments:

Operating & Maintenance - Section 3.2

SaskEnergy Incorporated

2000/2001 Cost of Service and Delivery Revenue Requirement Summary (in $ 000's)

Cost of Service	2000/2001 Application	BCUC Adjustments	2000/2001 Adjusted
Transportation & Storage	49,676		49,676
Operating & Maintenance	62,165	(2,114)	60,051
Depreciation	23,578		23,578
Corporate Capital Tax	2,634		2,634
Return on Rate Base	40,572		40,572
Cost of Service	178,625	(2,114)	176,511
Other Revenue and Adjustments			
Other Revenue - Revised	(4,169)	(201)	(4,370)
Distribution Tolls	(8,412)		(8,412)
Total Delivery Revenue Requirement	166,044	(2,315)	163,729
Less: Revenue at Current Rates	(162,455)	(1,091)	(163,546)
Rate Change: Revenue Deficiency(Surplus)	3,589	(3,406)	183
Percentage Rate Increase (Decrease) on Current Rates	2.21%		0.11%

Source of Adjustments:

Operating & Maintenance- Section 3.2
Other Revenue- Section 3.5
Distribution Tolls- Section 3.4
Revenue at Current Rates- Sections 2.3 and 5.1

SaskEnergy Incorporated

Cost of Gas Sold
(in $ 000's)

	1999/2000 Approved	1999/2000 Projected	2000/2001 Application	2000/2001 Adjusted
Cost of Gas Purchases	184,333	192,656	303,915	303,915
Transportation Costs	11,462	11,553	13,480	13,480
Net Change in Storage Inventory	(6,326)	(21,277)	(26,939)	(26,939)
Subtotal	189,469	182,932	290,456	290,456
Deduct Cost of SaskEnergy Internal Use	(1,240)	(1,486)	(2,116)	(2,116)
Cost of Gas	188,229	181,446	288,340	288,340
Interest Charge on Gas in Storage	0	0[1]	2,738	2,738
Other Operating Expenses	1,455	1,968	997	997
Cost of Gas Sold	189,684	183,414	292,076	292,076
Gas Cost Variance Account Balance	0	0	(156)	(156)
Adjusted Cost of Gas Sold	189,684	183,414	291,920	291,920
Quantity Sold, PJ	65.0	60.9	64.6	64.6
Cost of Gas Sales, $/GJ	2.92	3.01	4.52	4.52
Revenue at Current Rates			194,132	194,132
Revenue Deficiency			**97,788**	**97,788**
Volume Available for Recovery, $10^6 m^3$			1,748.9	1,549.0[2]
Rate Increase Required, $/m^3$			$0.0559	$0.0631[3]
Gas Consumption Charge (12 months), $/m^3$			**$0.1669**	**$0.1669**
Gas Consumption Charge (11 months), $/m^3$				**$0.1741[3]**

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1 The Saskatchewan Interim Rate Review Panel excluded the Interest Charge on Gas in Storage from 1999/2000 Gas Commodity Rates. SaskEnergy estimates this number as $1,516,000 for 1999/2000.

2 The Volume Available for Recovery from December 1, 2000 through October 31, 2001 is 1,549.0 $10^6 m^3$.

3 Effective December 1, 2000.

MINISTER'S ORDER

The Establishment of the Ministerial Advisory Committee Saskatchewan Rate Review Panel

I, John T. Nilson, Q.C., Minister of Crown Investments Corporation pursuant to section 16 of *The Government Organization Act* do hereby order that:

1. There shall be established a ministerial advisory committee known as the Saskatchewan Rate Review Panel (herein referred to as the Panel);

2. The Panel, as its mandate:

   (a) shall conduct a review and provide an opinion of the fairness and reasonableness of proposed Crown Corporation rate changes, referred to the Panel by the Minister of Crown Investments Corporation, considering the interests of the customer, the Crown Corporation, and the public; and

   (b) shall incorporate as part of its mandate specific terms of reference for particular Crown Corporation rate change reviews that may be attached by further minister's order.

3. Crown Corporation means SaskEnergy, SaskPower, and SGI AutoFund

4. The following persons are appointed as members of the Panel for a term not to exceed July 25, 2002:

Bob Lacoursiere	Saskatoon
Tracey Bakkeli	Regina
John Boan	Regina
Jo-Ann Carignan-Vallee	Assiniboia
Sheldon Craig	La Ronge
Joan Meyer	Swift Current

5. Bob Lacoursiere is designated as chairperson of the Panel;

6. In conducting its review, the Panel shall:

   (a) receive a rate change submission from a Crown Corporation;

   (b) establish procedures for conducting the review and ensure that these procedures are made available to the public;

   (c) engage the services of a consultant(s) to assist the Panel in its review of the fairness and reasonableness of the proposed rate change;

(d) make available to the public, prior to holding public meetings, the Crown Corporation rate change submission, with the exception of commercially sensitive information;

(e) hold public meetings and provide appropriate notification to the public of the date and location of public meetings, including any rules for public participation and Crown Corporation participation;

(f) provide members of the public with the opportunity to review and comment on the proposed rate changes to the extent reasonably allowed by the mandate of the Panel and by the schedule according to which the Panel is required to complete its work and provide its report to the Minister of Crown Investments Corporation;

(g) receive presentations of the consultant(s) or the Crown Corporation, review any written submissions and receive comments from the public;

(h) prepare a report on the Crown Corporation rate change submission for the Minister of Crown Investments Corporation after considering material received from the Crown Corporation, the consultant(s), the public, and its own analysis:

(i) where the Panel determines the rate changes as proposed are fair and reasonable, recommend that the changes be implemented; or,

(ii) where the Panel determines the rate changes are not fair and reasonable as proposed, recommend that the rate changes be adjusted providing reasons for this conclusion;

(i) provide its report respecting the proposed rate changes to the Minister of Crown Investments Corporation on a date set out in or within any time period after having received the rate change submission that is contained in specific terms of reference for particular Crown Corporation rate reviews; and

(j) make its report available to the public;

7. The Panel may utilize the services of such independent experts, clerks, reporters and assistants that are engaged on its behalf, as it deems necessary or advisable to aid and assist the Panel in its review;

8. Remuneration shall be paid to the panel members as follows:

(a) a retainer of $9,000 per annum and a per diem of $700 per day for the chairperson while engaged in the work of the Panel; and

(b) a retainer of $6,000 per annum and a per diem of $500 per day for the other members while engaged in the work of the Panel;

9. Panel members shall be reimbursed for traveling and expenses according to the approved Crown Investments Corporation policy outlined in the Remuneration Schedule and Expense Guidelines for Directors appointed to Crown Investments Corporation Subsidiary Crown Boards; and

10. Payment of remuneration, reimbursement and expenses incurred in the conduct and administration of the review shall be paid by Crown Investments Corporation.

Dated at the City of Regina, Saskatchewan, this 27th day of July, 2000.

Minister of Crown Investments Corporation

MINISTER'S ORDER

Saskatchewan Rate Review Panel
SaskEnergy Delivery Rate Change

WHEREAS by a Minister's Order dated July 27, 2000, issued pursuant to section 16 of *The Government Organization Act*, the Minister of Crown Investments Corporation appointed a ministerial advisory committee known as the Saskatchewan Rate Review Panel.

WHEREAS that Minister's Order provides for specific terms of reference for particular Crown corporation rate change reviews to be attached by further minister's order.

WHEREAS it is desirable to establish terms of reference for a SaskEnergy delivery rate change review and to attach the terms of reference to the previously mentioned Minister's Order.

NOW THEREFORE I hereby amend the said Minister's Order by attaching Appendix A affixed hereto as **"Schedule B: SaskEnergy Delivery Rate Change Terms of Reference"** to the said Minister's Order.

Dated at the City of Regina, Saskatchewan, this 5th day of October, 2000.

Minister of Crown Investments Corporation

APPENDIX A

Schedule B:
SaskEnergy Delivery Rate Change Terms of Reference

Terms of Reference

The Saskatchewan Rate Review Panel is requested to conduct a review of SaskEnergy's request for an increase in its delivery rates for the term November 1, 2000 to October 31, 2001.

The Panel shall provide an opinion of the fairness and reasonableness of SaskEnergy's proposed rate changes, considering the interests of the customer, the Crown corporation and the public.

In conducting its review, the Panel will consider the following factors:

The reasonableness of the proposed changes to the delivery rates, in the context of the following components:

1. SaskEnergy's forecasted delivery cost of service, comprised of:

I. the capacity that SaskEnergy has contracted for transportation and storage service;
II. operating and maintenance expenses;
III. depreciation expense; and
IV. Corporate Capital Tax.

2. The revenue requirement resulting from the delivery cost of service.

In conducting its review, the Panel shall consider the following as given:

I. the current operating rate structure;
II. the approved capital allocation, annual rate of return target, rate base, and corporate policies;
III. the existing service level; and
IV. the cost of service methodology and resulting study, which allocates SaskEnergy costs between the various rate classes.

The Panel will not publicly release or require SaskEnergy to publicly release commercially sensitive material.

Conduct of Review

The Panel will present its report to the Minister of Crown Investments Corporation no later than November 23, 2000.

MINISTER'S ORDER

Saskatchewan Rate Review Panel
SaskEnergy Gas Consumption Rate Change

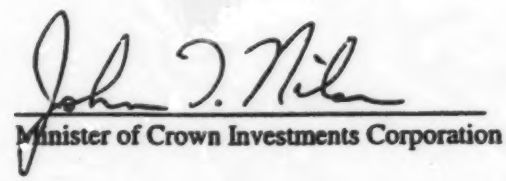
WHEREAS by a Minister's Order dated July 27, 2000, issued pursuant to section 16 of *The Government Organization Act*, the Minister of Crown Investments Corporation appointed a ministerial advisory committee known as the Saskatchewan Rate Review Panel.

WHEREAS that Minister's Order provides for specific terms of reference for particular Crown corporation rate change reviews to be attached by further minister's order.

WHEREAS it is desirable to establish terms of reference for a SaskEnergy gas consumption rate change review and to attach the terms of reference to the previously mentioned Minister's Order.

NOW THEREFORE I hereby amend the said Minister's Order by attaching Appendix A affixed hereto as **"Schedule C: SaskEnergy Gas Consumption Rate Change Terms of Reference"** to the said Minister's Order.

Dated at the City of Regina, Saskatchewan, this 5th day of October, 2000.



Minister of Crown Investments Corporation

APPENDIX A

Schedule C:
SaskEnergy Gas Consumption Rate Change Terms of Reference

Terms of Reference

The Saskatchewan Rate Review Panel is requested to conduct a review of SaskEnergy's request for an increase in its gas consumption rates for the term November 1, 2000 to October 31, 2001.

The Panel shall provide an opinion of the fairness and reasonableness of SaskEnergy's proposed rate changes, considering the interests of the customer, the Crown corporation and the public.

In conducting its review, the Panel will consider the following factors:

The reasonableness of the proposed changes to the gas consumption rates in the context of:

I. SaskEnergy's anticipated cost of gas for the effective term;
II. the Gas Purchase Contracts entered into by SaskEnergy for the supply of gas;
III. the amounts SaskEnergy pays for the transportation of gas;
IV. the natural gas commodity market conditions at the time of SaskEnergy's contractual commitments; and
V. the disposition of the balance of the Gas Cost Variance Account.

In conducting its review, the Panel shall consider the following as given:

I. the current operating rate structure;
II. the approved capital allocation, annual rate of return target, rate base, and corporate policies;
III. the existing service level; and
IV. the cost of service methodology and resulting study, which allocates SaskEnergy costs between the various rate classes.

The Panel will not publicly release or require SaskEnergy to publicly release commercially sensitive material including, but not limited to, its gas price hedging strategy and any details of its hedging or the gas purchase contracts.

However, the Panel may release the net effect of SaskEnergy's gas price hedging and gas purchase contracts.

Conduct of Review

The Panel will present its report to the Minister of Crown Investments Corporation no later than November 23, 2000.

Schedule "A"

Services Provided by BCUC

1. Provide professional expertise, advice and services to the Panel pertaining to a review of SaskEnergy's requests for an increase in gas consumption charges and delivery service rates.

2. Prepare and deliver to the Chair of the Panel a report on SaskEnergy's requests for an increase in gas consumption charges and delivery service rates. The report should:

   - review whether SaskEnergy's proposed rate changes are fair and reasonable; and
   - provide a recommendation to the Panel regarding SaskEnergy's rate proposals.

3. Attend meetings as required by the Chair of the Panel.

THE BRITISH COLUMBIA UTILITIES COMMISSION STAFF

General

The British Columbia Utilities Commission is an independent regulatory agency of the Provincial Government operating under and administering the Utilities Commission Act. The Commission's primary responsibility is the regulation of the 20 energy utilities and pipelines under its jurisdiction to ensure that the rates charged for energy are fair, just and reasonable, and that utility operations provide safe, adequate and secure service to their customers. The Commission approves the construction of new facilities planned by utilities and their issuance of securities. The Commission's function is quasi-judicial and its decisions and orders may be appealed only to the Court of Appeal on questions of law or jurisdiction. The Commission members are appointed for specific terms by the Cabinet, through the Lieutenant Governor-in-Council.

The Commission's professional staff are hired independently by the Commission under the powers of the Utilities Commission Act and are separate from the Public Service Act. Commission staff provide technical advice and administration support to the Commission in all areas including engineering, finance and accounting, economics and rate design, and review of commodity contracts. Bill Grant is the Executive Director of the Commission and the most senior staff position, reporting directly to the Chairperson. Brian Williston is the Manager, Engineering and Commodity Markets and is responsible for the review of natural gas and electricity supply contracting practices and of applications for major facility additions. James Fraser is the Manager, Strategic Services and is responsible for the review of utility load forecasts, return on equity and capital structure matters, and rate design applications. Philip Nakoneshny is Senior Financial Analyst, reporting to the Manager, Rates and Finance, who is responsible for the review of revenue requirements applications. Biographies are attached.

Revenue Requirements Application Review

In British Columbia, the Utilities Commission Act provides that the only rates a public utility can lawfully charge and the only terms and conditions of service that it can apply, are those which have been filed with and accepted by the Commission. Rates must strike a balance between being a fair charge for the service provided to the customer, while permitting the utility to earn a reasonable return on its investments required to provide these services.

A revenue requirements application generally compares, for a future test period such as the next year, a forecast of the revenue generated using current rates to a forecast of the utility's cost of providing service.

The utility usually requests adjustments to customer rates to eliminate any forecast revenue deficiency or surplus. Utility costs such as operating, maintenance and administration expenses, depreciation charges, interest charges, income and other taxes, and a fair return on its equity investment, are typically recovered in fixed Monthly Charges and variable Delivery Charges. Costs related to the gas commodity are flowed-through to customers without any mark-up by the utility, and are recovered in variable Gas Consumption Charges.

Rate design is the allocation of the utility's revenue requirement to individual rate classes of customers, and the structuring of the components of rates for each class. Rate design is generally reviewed less frequently than revenue requirements. Between rate design reviews, the Commission makes revenue requirement adjustments to rates in a manner that is consistent with the rate structure and specific directions that were approved in the last rate design proceeding.

A revenue requirement application for changes to delivery rates generally requires a public hearing. Because of the adversarial nature of the traditional public hearing process, hearings can become long and costly. The Commission has introduced the following approaches in an effort to reduce costs and save time:

Negotiated Settlement Process ("NSP")

NSP has been very successful by eliminating the need for a hearing on many applications and reducing the scope of matters that need to be reviewed in other cases. In the negotiation process, individuals representing various interests openly explore issues set out in the utility's application, with the purpose of reaching common understanding of the underlying interests. Recommended solutions and agreements are arrived at through collaboration and consensus. Trade-offs between competing objectives are encouraged so that the final settlement maximizes the overall needs of the participants. Commission staff are active participants to ensure that all ratepayers are represented. Settlements are subject to Commission approval.

Performance Based Regulation ("PBR")

PBR mechanisms are used to streamline rate setting, and to implement incentives to utilities to trim costs while maintaining high quality service. A PBR mechanism typically sets a baseline revenue requirement by expense category that can be modified for inflation, productivity and other factors in the future. Both customers and shareholders are rewarded for management measures that result in costs below the baseline. Costs, like taxes, that are beyond the control of the utility are recovered at cost. Quality control measures ensure that the utility does not pursue costs savings at the expense of system reliability, safety and

customer satisfaction. PBR arrangements typically run for several years, with annual meetings to review progress and performance.

Other Processes

The Commission frequently uses workshops, pre-hearing conferences and town hall meetings as part of the hearing process. Workshops are educational sessions prior to a hearing, so that all parties have a similar level of understanding. Pre-hearing conferences optimize the hearing schedule, and attempt to identify non-contentious issues that may be removed from the scope of the hearing. Town hall meetings are less formal hearing sessions that are held at times, and in locations, which are more convenient for members of the public likely to be affected by the application.

Rather than an oral public hearing, the Commission sometimes uses a written hearing where the subject is technical and if limited interest to the public, or an Inquiry by a single Commissioner where the issue is fairly well defined and localized.

Generic Hearings

Where issues are common to several utilities, the Commission reviews the matter in a single generic hearing. This approach has been used to determine the appropriate rate of return on equity for the major utilities it regulates, and to develop a mechanism for calculating the return for future years.

Energy Supply Contract Review

In British Columbia, Section 71 of the Utilities Commission Act provides that the Commission must review and accept the commodity contracts entered into by each utility. The Commission must determine that the quantity of natural gas contracted for, and its availability, are sufficient for the needs of the core customers of the utility. The Commission must also determine that the prices in those contracts are competitive. In practice, Commission staff have an ongoing dialogue with the natural gas supply departments of the affected utilities to agree on a contracting plan early in each year and the Commission then accepts individual contracts that are consistent with the contracting plan. The utilities enter into a portfolio of natural gas contracts, including baseload contracts, peaking contracts, seasonal contracts, and underground storage contracts. BC Gas Utility Ltd. ("BC Gas") also stores gas in its liquified natural gas facility. The various contracts will include both variable priced and fixed priced contracts, along with a price risk management program to attempt to obtain the lowest overall price for the customers.

British Columbia is not blessed with underground storage nearby the primary load centre in the Lower Mainland. This circumstance, coupled with the poor load factor of the residential and commercial customers which make up the bulk of the utility core sales, results in contracting plans which are more diverse than may be necessary for a utility with local storage options.

In British Columbia each gas utility is permitted to flow-through its actual cost of gas purchases to customers. Each utility has a gas cost reconciliation account to record the difference between the actual cost of gas purchases and the revenues recovered through the gas commodity component of rates. Positive or negative balances in the account are passed through to customers in future rates. In specific instances, the Commission has approved phased-in commodity cost increases to avoid rate shock to customers. While this process has had the advantage of smoothing the rate increases to customers, it has been criticized as blunting the market signals to customers.

WILLIAM JOHN GRANT, B.SC. (Eng.), MBA, CFA

Bill has been employed by the British Columbia Utilities Commission and its predecessor, the British Columbia Energy Commission, for more than 20 years. For the past 12 years he has been the Executive Director of the Commission. Prior to Commission employment he worked for Transport Canada and the Institute of Guided Ground Transport.

Bill has initiated or been involved in the development of many energy regulatory reforms including the following:

- Natural gas commodity competition and unbundling of utility tariffs. British Columbia was the first province to allow industrial customers to purchase gas directly from producers or marketers. The process of unbundling utility costs lead the Commission to initiate a bypass methodology which has been adopted by many jurisdictions;

- An automatic return on equity adjustment mechanism was first implemented in Canada by the Commission;

- The Commission has been using and refining its multi-year, performance-based rate making process over the past five years;

- The Commission has selectively used alternative dispute resolution techniques for more than ten years. Most utility rate and rate design applications are settled rather than going to public hearing; and

- The Commission first implemented wholesale electricity competition in 1996 and the first retail access application was approved in 1999.

Bill completed a Masters of Business Administration degree immediately following his undergraduate Bachelor of Science degree. He has been a Professional Engineer in Ontario and British Columbia and he returned to academic study to obtain a Chartered Financial Analyst designation from the University of Virginia. Bill enjoys skiing and mountain biking. He does not enjoy revenue requirements hearings.